CRANFIELD UNIVERSITY

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A Surface-Subsurface Model for the Techno-Economic and Risk Evaluation of Thermal EOR Projects

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ABSTRACT

The global resources of unconventional oil such as heavy oil, extra-heavy oil, and bitumen are vast and are expected to play an increasingly important role in meeting the world's future energy needs. However, the highly viscous nature of these resources means that only a small fraction of them can be recovered by the simple and inexpensive primary and secondary oil recovery techniques. A greater fraction demands complex and costly tertiary oil recovery techniques known as Enhanced Oil Recovery (EOR). Of the various EOR techniques available today, the recovery of viscous oil remains inextricably tied to steam-based EOR (S-EOR). S-EOR involves the injection of large quantities of steam into the reservoir in order to reduce the oil viscosity to improve its mobility, and thus increase oil production.

The economics of S-EOR projects is governed by the time-rate of the recovery of oil versus the time-rate of expenses required to recover this oil. Steam generation is typically the largest cost component in S-EOR projects and it accounts for more than fifty percent of the total operating cost. Despite this, the focus during preliminary development phases is often on maximizing the oil production rate rather than optimizing long run economics. It is argued throughout this study that for optimum S-EOR development, the decision-making process should be based upon optimizing the long term economics. A multidisciplinary approach that includes considerations of surface, subsurface, environmental, and risk perspectives is therefore needed.

This thesis reports on the development of TERM-EOR, an integrated surface-subsurface tool to enhance the decision-making processes involved in S-EOR projects. The tool consists of economic, fiscal, environmental, and risk modules that are fully integrated in a single user-friendly platform. The tool can be used both during project feasibility studies and for operation optimization.

The use of TERM-EOR is illustrated through two case studies, one of which is surface-oriented while the other is subsurface-oriented. In the first case study, the thermodynamic performance of gas turbine cogeneration in a typical S-EOR project is evaluated and its economics is compared with a fired boiler system. Cogeneration was

found to provide substantial fuel savings and CO_2 reduction, and its economics remains competitive even under the most unfavourable conditions. The unit technical cost (UTC) of the project with cogeneration was found to be between 2 to 10 dollars lower than the project without. In addition, the break-even oil price for the project with cogeneration was also found to be 6 to 8 dollars lower than that without.

In the second case study, TERM-EOR is used to optimize the operating pressure of a Steam Assisted Gravity Drainage (SAGD) project. It was found that there is no cut-off answer to the question of optimum operating pressure for SAGD. The answer is found to be influenced by a number of factors including the obtained oil rate, the steam to oil ratio, crude oil prices, steam technology and steam cost, as well as the environmental regulations in place. Operating at high pressure, though resulting in higher oil rates, increases steam consumption, fuel usage and GHG emissions. On the other hand, operating at low pressure is thermodynamically more efficient but results in lower oil rates. In general, from a government viewpoint the economics of the SAGD project was found to be more sensitive to the obtained oil rate, and thus favouring high pressure operations. This is in contrast to the oil company perspective where the economics was found to be driven by the operating costs, and thus favouring low pressure operations.

A preliminary thermodynamic evaluation of a parabolic-trough solar system designed to deliver steam for S-EOR projects was carried out. The study highlights a number of technical challenges facing the integration of solar technology into S-EOR operations. For a typical day in Oman, it was found that the steam injection process can only be maintained for less than nine hours a day, after which the steam injectors will be shut-in. The cyclic cooling and heating of injector wells will expose them to fatigue problems, which may result in premature failures. Solar-generated steam will also have to be injected at peak rates during daytime in order to compensate for steam unavailability during the night. The peak in steam rate for the solar case was found to be three times greater than that required for constant-rate operation. Therefore, more steam injectors and larger steam facilities with high turndown capabilities are required to handle peak steam rates. It will also raise concerns about the steam injectivity of the reservoir and whether it will be able to handle peak steam rates associated with solar steam plants, an issue which is still open to debate.

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NOMENCLATURE

API	American Petroleum Institute
AGR	Advanced Gas-Cooled Reactor
BP	British Petroleum
Barg	Pressure (gauge)
Bopd	Barrel of Oil per Day
Bspd	Barrel of Steam per Day
BWR	Boiling Water Reactors
CSS	Cyclic Steam Stimulation
CWE	Cold Water Equivalent
CNEA	National Atomic Energy Commission
CERI	Canadian Energy Research Institute
CAPEX	Capital Expenditure
EOR	Enhanced Oil Recovery
GT	Gas Turbine
GHG	Green House Gases
HHV	Higher Heating Value
HRSG	Heat Recovery Steam Generator
HTR	High Temperature Reactor
HTF	Heat Transfer Fluid
HGP	Hot Gas Path
GTGR	High Temperature Gas Cooled Reactor

IAEA	International Atomic Energy Agency
IOC	International Oil Company
IOR	Improved Oil Recovery
IEA	International Energy Agency
LHV	Lower Heating Value
Mtoe	Million Tonnes of Oil Equivalent
MMBtu	Million British Thermal Unit
OPEX	Operating Expenditure
OTSG	Once Through Steam Generator
PDO	Petroleum Development Oman
PWR	Pressurised Water Reactor
PBMR	Pebble Bed Modular Reactor
Ppm	Parts per Million
SOR	Steam to Oil Ratio
SPE	Society of Petroleum Engineers
S-EOR	Steam Based Enhanced Oil Recovery
SAGD	Steam Assisted Gravity Drainage
TIT	Turbine Inlet Temperature
TDS	Total Dissolved Solids
TAGOGD	Thermally Assisted Gas Oil Gravity Drainage
VIGV	Variable Inlet Guide Vane
WPC	World Petroleum Council
WTI	West Texas Intermediate

1 Introduction

1.1 The Need for Unconventional Oil

The recognition of the significance of unconventional oil resources and its growing role in the global oil supply provides a motivation for this study. The potential importance of these resources can be appreciated by first considering their quantities and the available market for them.

1.1.1 Definitions

The process for estimating hydrocarbon reserves is complex by nature, requiring both scientific methodologies and expert interpretations. The interchangeable use of imprecisely defined terms adds further complication to the process. This is particularly true for the terminologies used in the classification of petroleum resources which have been the subject of ongoing revision and subsequent amendments for decades. In fact, it was not until 1997 when the Society of Petroleum Engineers (SPE) and the World Petroleum Council (WPC) joined efforts to develop a set of reserve definitions that would improve the level of consistency in reserve estimation and reporting in a worldwide basis (McMichael, et al., 1997). The document was recently updated and additional definitions were added (SPE, 2005) (SPE, 2007). For consistency, the latest SPE definitions are used throughout this thesis. Some of the terms that are particularly relevant to this study are explained here:

Oil-in-Place: is the total quantity of petroleum that is estimated to exist originally in naturally occurring reservoirs. This includes both *producible* and *non-producible* oil. Due to limitations in oil production technologies and characteristics, only a fraction of the oil-in-place can be produced. The *producible* fraction is called reserves.

Proved Oil Reserves: this is generally taken to be those quantities of petroleum, which geological and engineering information indicates with reasonable certainty, can be commercially recovered from known reservoirs under current economic conditions, operating methods, and government regulations. Therefore, proved reserves must satisfy four main criteria (SPE, 2007):

- discovered
- recoverable using existing technology
- commercially viable
- remaining in the ground

Recovery Efficiency (or Recovery factor):is a numeric expression of the portion of in-place quantities of petroleum estimated to be recoverable by specific processes or projects, most often represented as a percentage. The recovery factor varies greatly among oil fields and may change over time based on operating history and in response to changes in technology and economics.

Conventional Crude Oil: petroleum found in liquid form, flowing *naturally* or capable of being produced without further processing or dilution.

Unconventional Oil: there is no universally agreed definition of the term unconventional oil as opposed to conventional oil. For some, unconventional oil is any source of oil that requires production technologies significantly different from those used in the mainstream reservoirs exploited today. This is, however, clearly an imprecise and to some extent a time-dependent definition. What is considered unconventional under today's economic and technological circumstances may well become conventional in the future when the technology used to extract it becomes the norm rather than exception (IEA, 2010).

A more precise definition is based on the viscosity of the crude oil. Viscosity-based classification was first agreed upon in the 1982 UNITAR conference in Venezuela (Khayan, 1982). The proposed definitions are summarised in Table 1-1 (Laurier, 1992). Accordingly, the oils are to be characterised based on viscosity, with the density to be used only if viscosity measurements are not available. The American Petroleum Institute (API) gravity is also used to classify oils. Under this classification, all oils with API gravity below 20 (i.e. a density greater than 934 Kg/m^3) are considered to be unconventional. For reference, conventional light oil such as Brent and West Texas crudes has API gravities in the range 38-40.

Table 1-1: Oil Classifications

Classification	Viscosity (cP)	Density Kg/m^3	API Gravity
Light Oil	<10,000	<934	>20
Heavy Oil	<10,000	934-1000	20-10
Extra-Heavy Oil	<10,000	>1000	<10
Bitumen	>10,000	>1000	<10

The main disadvantage of viscosity-based classification is that it does not always reflect the technology used for production. For example, some oils located in deep offshore reservoirs in Brazil have API gravity of 20 and therefore should be classified as unconventional under viscosity- based system. However, these oils are extracted using entirely conventional techniques (IEA, 2010).

The International Energy Agency (IEA) includes oils obtained from kerogen contained in oil shales, from coal through coal-to-liquids technologies, and from natural gas through gas-to-liquids technologies in its definition for unconventional oil. These oils, however, do not fit into the viscosity-based definitions.

Throughout this study the term ‘heavy oil’ is used to collectively describe heavy oil and extra-heavy oil. This includes oils having viscosity of 100 to 10,000 cp[1], and if viscosity is not available API gravity between 10 and 20 is used. The term ‘oil sands and bitumen’ is used to describe oils having viscosity greater than 10,000 cp, or API gravity of less than 10. Furthermore, the term ‘unconventional oil’ is used to collectively describe heavy oil, extra-heavy oil, and bitumen.

1.2 Energy Market Review

The inexorable rise in global demand for energy is resuming[2] as the world comes out of recession. In its 2010 release of the World Energy Outlook, the International Energy Agency (IEA) projected that the world’s primary energy demand will increase by 36% between the year 2008 and 2035, from around 12 300 million tonnes of oil equivalent

[1] cP (Centipoises)

[2] Surging oil prices in 2008 and the subsequent collapse of the global financial market temporarily weakened the demand for oil in 2009. Oil demand dropped from about 85 million bopd in 2008 to 84 million bopd in 2009

(Mtoe)[3] to over 16 700 Mtoe, at a rate of 1.2 % per year. This projection, referred to in the report as new policies scenario, takes into account the broad policy commitments and plans that have been announced by countries around the world to reduce greenhouse gas (GHG) emissions and plans to phase out fossil-energy subsidies. The IEA report has also considered a second scenario (the current policies scenario) where it was assumed that the current policies as in mid-2010will remains in place throughout the study period. The third scenario (the 450 scenario) sets out an energy pathway consistent with the 2°C goal through limitation of the concentration of GHG in the atmosphere to around 450 parts per million of CO_2 equivalent (ppm CO_2-eq). The 450 scenario simply represent radical policy actions to curb fossil fuel use. Not surprisingly, the annual projected rate of growth in energy demand is the lowest for the 450 Scenario, at 0.7% per year, and is the highest for the current policies scenario, at about 1.4%.

Interestingly, oil remains the dominant energy source in 2035 in all three scenarios, including the *anti-fossil* 450 scenario. Under the new policies scenario, oil will account for about 28% of the global energy mix in the year 2035. The share is higher in the current policies scenario (33%) and is lower in the 450 scenario (26%). In absolute terms, oil use is projected to increase under new policies scenario from 84 million bopd in 2009 to 99 million bopd in 2035.

1.3 The World Oil Resources

It is evident that even under the strictest anti-fossil fuel projection scenarios; the world will remain dependent on oil as the primary source of energy for decades to come.

An increase in oil production and exploration activates is therefore needed to cope with growing demands. Shortages in oil supply will undoubtedly cause oil prices to skyrocket, with potentially severe economic and social consequences. In fact, the perception that surging oil demands will eventually outpace supply is believed to be one of the factors in the recent spikes in oil price.

[3]Based on IEA definition, toe = 4.187 GJ of energy

A legitimate question one may ask is if the world has sufficient oil resources to meet future demand and whether future oil supply will be resources-limited or technology-constrained, or a combination of both.

With few expectations, the planet has been explored exhaustively to the point where the industry has reasonably a good estimate of the global oil resources. The global oil resources are vast and are estimated to total 9 to 13 trillion barrels of *oil-in-place* (Hussein, et al., 2006) (Ivan, et al., 2007). Unfortunately, not all of the oil in-place is recoverable because of a number of geological and technological limitations. Traditional recovery methods typically recover on average less than one-third of the oil in-place leaving behind as much as 78% of the discovered oil untouched (Larry, et al., 1992) (National Petroleum Council , 2007)(Ivan, et al., 2007)(IEA, 2009).

Beside geological and technological limitations, there are also a number of economic factors that contribute to the overall low recovery factor. Not long time ago, the perception in the oil industry was that the cost of newly found barrel of oil is far less than the cost of incremental oil from ageing fields and that new oil was relatively easy to find. There is always a point where the cost of producing an extra barrel of oil from a depleting field is higher than the market price for that barrel. As a result, the field is abandoned with a lot of oil still being left behind and production starts from a green-field.

Although, additional oil capacity from green-fields is expected to increase over the next few years, there is a great deal of speculation and uncertainty as to whether they will be sufficient to compensate for the increase in demand and the rapid decrease in production. A recent statistical report published by British Petroleum (BP) showed sluggish worldwide exploration records for the past two decades, see Figure 1-1 (BP, 2010). Figure 1-1 also shows a noticeable increase in the global oil reserves toward the end of 2009. This is largely due to additional extra-heavy reserves found in the Venezuelan Orinoco Oil Belt. It is worth to note that the data presented in Figure 1-1 are the *proved reserves* which and for this reason they are less than the reported global oil-in-place resources. In addition, this reserve estimation does not include the vast Canadian oil sands deposits.

The IEA (2010) predicted that aggregate output from fields already in production in 2009 is declining at a rate of 8.3% per year. At this rate, the IEA estimated that there is a need to add a total of 67 million barrel of oil per day (bopd) of gross capacity in order to compensate for the decline in existing conventional oilfields. In fact, The IEA expects that less than 60% of the crude oil produced from new fields in 2035 is from fields that have already been found. The bulk of the oil that is needed by the year 2035 will come from new fields that *are yet to* be found. Shortage in conventional oil supply is expected to be replaced mainly from natural gas-to-liquid, oil from deep water resources, and unconventional oils resources (IEA, 2010).

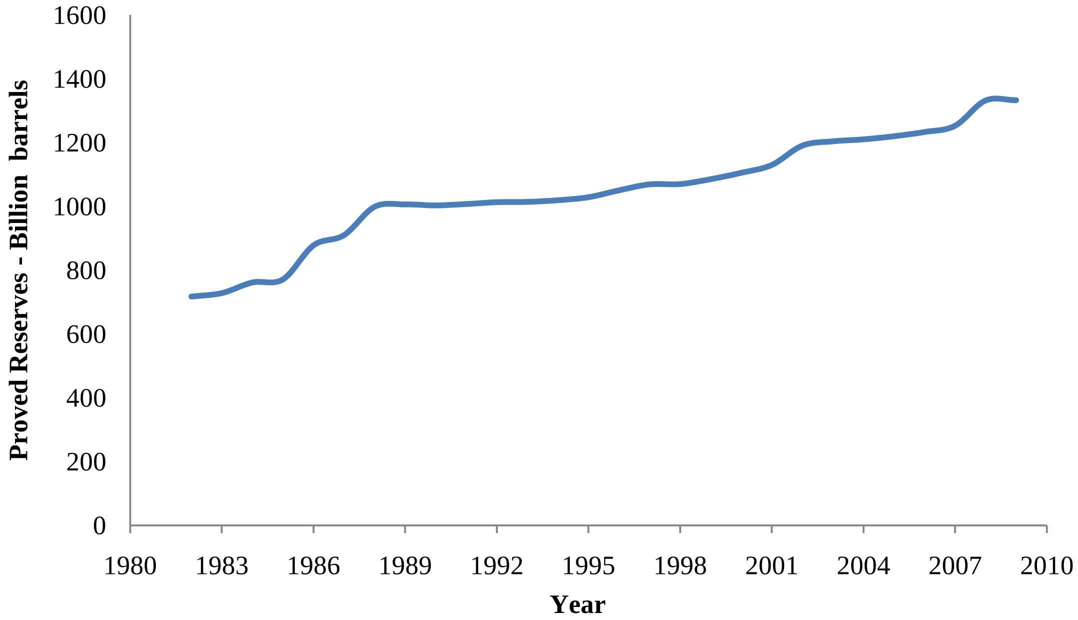


Figure 1-1: The world proved oil resources (BP, 2010)

1.4 Unconventional Oil Resources

The global unconventional oil resources are vast and are estimated to be several times larger than conventional oil resources. In fact, only 30% of the world's total oil reserves are considered conventional; with the remaining are classified as heavy oil, extra heavy oil, and bitumen (Hussein, et al., 2006). Figure 1-2 illustrates percentage shares of these resources.

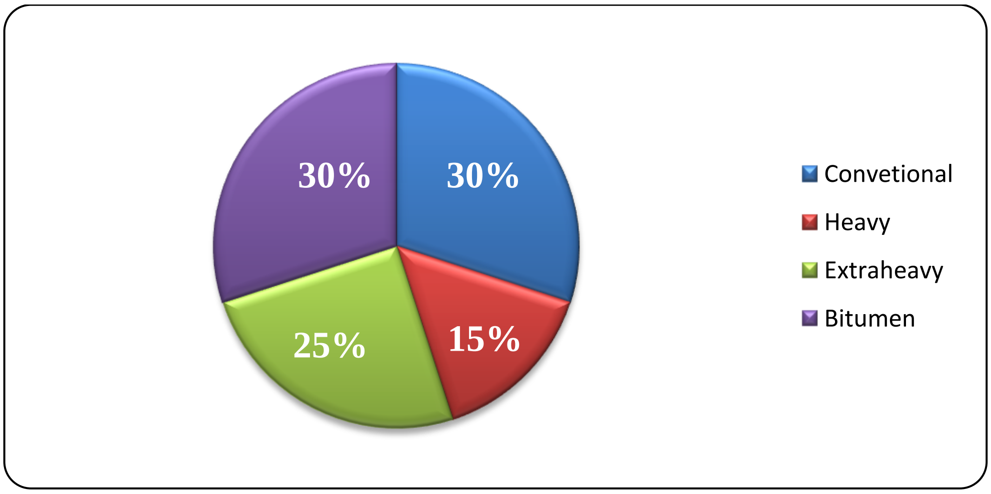


Figure 1-2: Percentage allocation of global oil reserves (Hussein, et al., 2006).

Except for Canada, Venezuela, and to some extent the US, precise quantitative reserves and oil-in-place of unconventional oil are seldom available to the public. It is well known, however, that these counties hold the largest deposits of unconventional oil resources in the world. Canada alone is estimated to have 175 billion barrels of *proved* bitumen reserves (Oil & Gas Journal, Dec 2010). In fact, Canada until recently contained the world's second largest proved oil reserves, just after Saudi Arabia. This, however, changed in 2009 when Venezuela announced that it has increased its proved reserves from 99.3 billion barrels in 2009 to over 221 billion barrel in 2010, catapulting the country to second behind Saudi Arabia (Oil & Gas Journal, Dec 2010). Another estimate for the Venezuelan heavy oil resources is provided by the US Geological Survey (USGS) which estimates that the Orinoco Oil Belt contains a volume of 380 to 652 billion barrel of *technically*[4]recoverable heavy oil (USGS, 2009).

Significant quantities of heavy oil and tar sands are also found in the United States (U.S). The U.S. is estimated to have 104 billion barrels of oil-in-place of heavy oil (Edward, 1998) and another36 billion barrels of bitumen (USGS, 2006). Other counties such as China, Indonesia, Oman, the Neutral Zone[5], Russia, and Kazakhstan are also known to have significant quantities of unconventional oils.

[4]Technically recoverable resource is generally used to define the proportion of the estimated oil-in-place which is recoverable using current exploration and production technologies without regard to cost.

[5] An area of 5,770 km² between the borders of Saudi Arabia and Kuwait left undefined

1.5 Enhanced Oil Recovery (EOR)

The highly viscous nature of unconventional oil resources means that only a small fraction of it can be recovered by the simple and inexpensive primary[6] and secondary[7] oil recovery techniques.

A greater fraction, however, demands complex and costly tertiary oil recovery techniques or, what is commonly known in the industry as 'enhanced oil recovery' EOR. The term enhanced oil recovery has been used historically to describe the third step (otherwise known as tertiary recovery) in oil production (see Figure 3-1).

A more precise definition used by the Oil & Gas Journal is that EOR projects are those projects that involve the injection of fluids, other than water or methane, into an oil formation to improve the oil recovery process. This includes any fluids that do not *originally exist* in the reservoir.

This definition is helpful because it distinguishes between EOR and another term commonly used in the industry which is improved oil recovery (IOR). The latter is generally used to describe all practices to increase oil recovery including for example EOR processes, infill drilling, and horizontal wells technology (Roger, et al., 2004).

EOR contributes to the global oil market in two ways: by increasing or reviving oil production from oil fields depleted of more easily recoverable oil through primary or secondary oil recovery methods. In other instances, EOR allows the production of oil from alternative resources previously thought to be technologically infeasible or economically unviable. An example of the latter is unconventional oil resources.

[6]Primary Recovery: production occurs due to natural reservoir pressure until depletion.

[7]Secondary Recovery: after natural reservoir drive diminishes, secondary recovery methods are applied. They rely on restoring (or maintaining) the reservoir pressure by the supply of external energy into the reservoir in the form of injecting fluids such as water or natural gas.

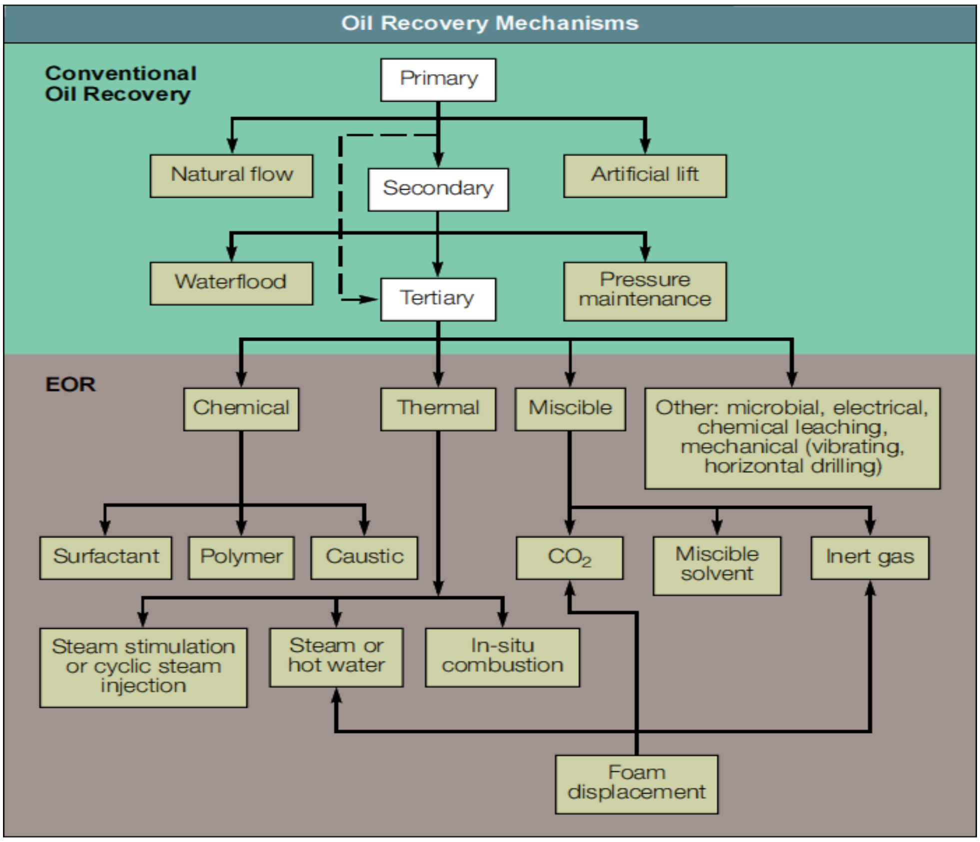


Figure 1-3: Oil recovery techniques (Larry, et al., 1992)

The choice of injected fluids depends on various oil properties (gravity, viscosity, compositions) and reservoir characteristics (oil saturation, thickness, depth, and temperature); limiting the applicability of certain EOR methods. The most common injectants include (Guntis, 2010):

- Steam (heavy oil at shallow depths)
- CO_2 (light oil)
- Chemical and polymer (light oil)
- Hydrocarbon miscible gas (light oil)

Reservoir lithology is one of the screening criteria available during EOR evaluation. Based on a database from a collection of 1507 active and inactive projects worldwide EOR, Vladimir, et al (2010) showed that thermal and chemical EOR are the most widely used methods in sandstone reservoirs, see Figure 1-4.

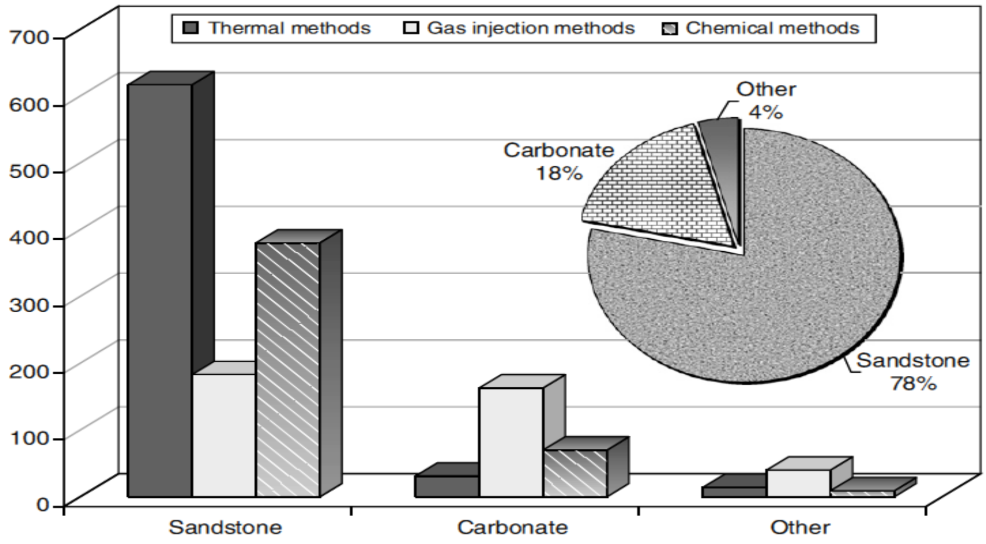


Figure 1-4: EOR methods by lithology for a total of 1507 worldwide projects

Taber, et al (1983) developed technical screening guides that can be used to select among the various EOR methods. Their work was later updated to reflect more laboratory testing and additional field data that became available as more EOR projects became operational (Taber, et al., 1997). These screening criteria are useful for cursory evaluation of many candidate reservoirs before extensive (hence expensive) reservoir and economic evaluations are carried out. The selection criteria for a number of EOR methods are given in Table 1-2(Taber, et al., 1983) (Taber, et al., 1997).

It is can be seen from Table1-2 that there is no single EOR method that fits all type of reservoirs and oils. Generally, $CO_{2,}$ nitrogen, and hydrocarbon miscible flooding work best with light oils at a wide range of formation depth. At the other extremes, reservoirs containing highly-viscous oils are difficult to mobilize by methods other than thermal EOR. This could explain the overwhelming popularity of thermal EOR in counties like the U.S., Canada, Venezuela, and Indonesia where vast quantities of unconventional oils are known to exist.

Guntis (2008) survey and reported on the operational and proposed EOR projects worldwide. There are two key observations that can be made from his extensive survey. The first is that thermal EOR methods remain the dominant EOR method worldwide, although gas-based EOR processes particularly CO_2 injection are gaining increasing popularity; see Figure 1-5. Moreover, thermal EOR methods are predominately used in heavy oil, extra-heavy oil, and oil sands projects. As an example, the ranges of oil properties and reservoir characteristics of projects that are currently producing in the US through thermal and CO_2 injection are summarized in Table 1-3. It is evident that highly viscous oil is almost being exclusively produced by thermal EOR methods. Given the fact that this study is concerned about the recovery viscous oils, emphasis will be placed on thermal EOR methods hereafter.

Table 1-2: EOR technical screening guides

	Gravity (API)	Viscosity (cp)	Thickness (ft)	Depth (ft)	Oil Saturation
Steam	>8-25	<100,000	>20	<5,000	>40
In-Situ Combustion	10-27	<5,000	>10	<11,500	>50
CO_2	>22	<10	wide range	>2,500	>25
Polymer	>15	<150	not critical	<9,000	>50

Table 1-3: Field characteristics of EOR projects in the U.S.

	CO_2		Thermal	
	Miscible	**Immiscible**	**Steam**	**Combustion**
Depth, ft	1500 – 11,950	1,150 – 8,500	100 - 2,300	400 - 9500
API Gravity	28 - 44	11 – 35	10 - 30	19-38
Viscosity, cp	0.6 - 6	0.6 - 45	20 - 51,000	1.4 - 2

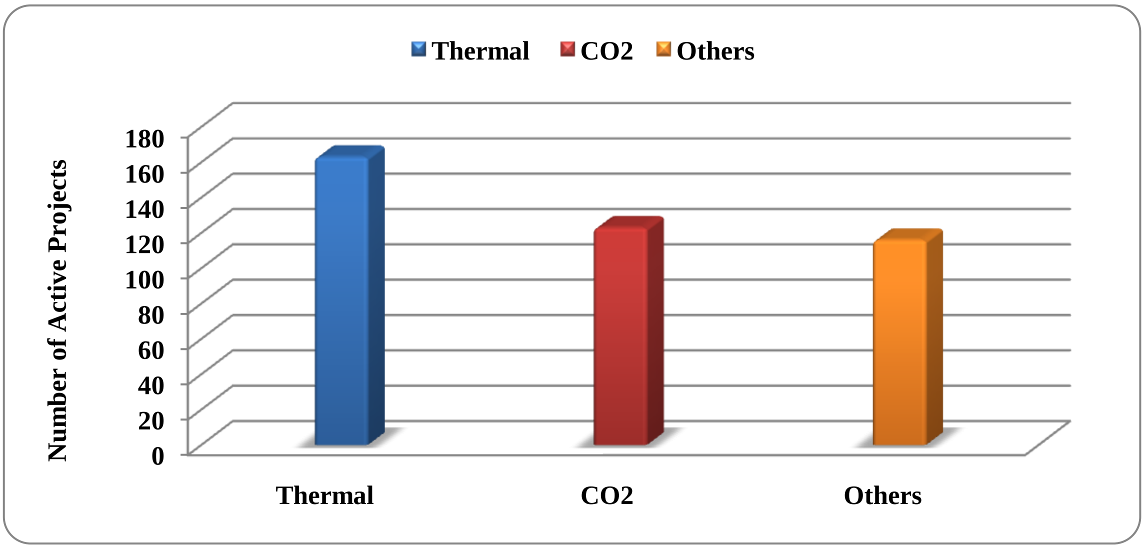


Figure 1-5: Worldwide active EOR projects (Guntis, 2008)

1.6 Thermal EOR

The primary purpose of thermal recovery is to reduce the in-situ viscosity of the crude in a reservoir so that it can be produced more readily. This is primarily achieved by increasing the temperature of the crude through heat addition.

There are broadly two categories of thermal EOR methods: those in which heat is generated within the reservoir itself and those in which a hot fluid is injected into the reservoir (Michael, 1986). In the former, air is injected into the reservoir and fraction of the in-situ hydrocarbon (about 10%) is fired to generate the required heat (Taber, et al., 1997). This process is commonly known as in-situ combustion but other terms such as underground combustion or fireflooding are also used. Significant amount of fuel is burned both above the ground to compress the air and below the ground in the combustion process.

In-situ combustion, although performs well in the laboratory, is not practised to any great extent today due to its inherent complexity. The principal problem in in-situ combustion projects is the lack of combustion front control (Sarathi, et al., 1994). Villalba, et al (1994) reviewed four in-situ combustion projects in Venezuela. The review indicated that the most common operational issues are corrosion problems in the production wells as well as difficulties in controlling the rate and direction of the burning front. Farouq (1994), an expert and pioneer in the field of thermal EOR, described in-situ combustion as the most tantalizing EOR method because it works under most conditions but it is seldom profitable. Sarathi, et al (1994) showed that only one of eight cost-shared in-situ combustion projects in the U.S was an economic success. As of 2008, there were only 21 operational in-situ combustion projects worldwide, of which 14 are in the U.S. and Canada, and they are dominantly applied to relatively light-oil fields (Guntis, 2008).

An alternative method to heat the reservoir is to inject high pressure steam into the subsurface formation to heat the oil and hence reduce its viscosity. Steam-based EOR method, referred hereafter as S-EOR, is the oldest EOR method and it began approximately five decades ago. Kern River fields in California and Tia Juana fields in Venezuela are among the earliest S-EOR projects in the world (Vladimir, et al., 2010).

Today, S-EOR remains the dominant EOR method worldwide. About 35% of worldwide active EOR projects that are reported by Guntis (2008) use steam as the injection fluid. Within thermal EOR, steam-based projects significantly outnumber in-situ combustion. As in 2008, there were 145 producing S-EOR projects, representing more than 87% of the total thermal projects worldwide, see Figure 1-6.

Both theory and statistics suggest that the recovery of viscous oils is inextricably tied to S-EOR methods. In keeping with this conclusion and the fact that this study is focusing on unconventional oil extraction, discussion hereafter are focused on S-EOR methods.

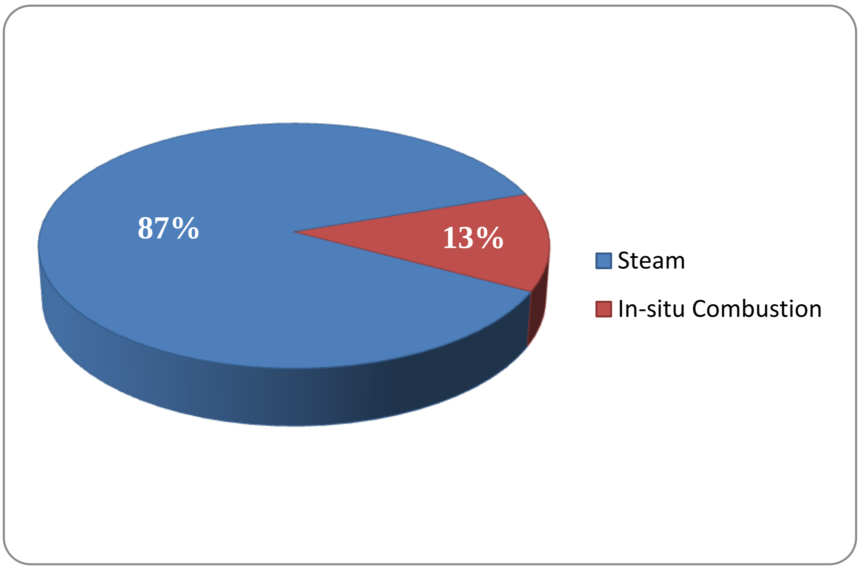


Figure 1-6: Worldwide active thermal EOR projects (Guntis, 2008)

1.7 Research Objectives and Methodology

The decision-making process in S-EOR developments requires complex and multidisciplinary team efforts in order to evaluate the various surface, subsurface, economic, financial, and environmental aspects of the project. However, preliminary project evaluation typically focuses on maximizing the oil rate rather than optimizing the long run economics. This is mainly due to the fact that little information about the characteristics and economics of surface facilities is available during early project development, which leaves reservoir engineers with no option but to optimize the oil rate, which may or may not optimizes the long terms economics. It is argued throughout this study that for an optimum decision making, an integrated surface and subsurface evaluation is needed.

The study described in this thesis has three main objectives:

- To initialise the development of a novel integrated computational tool that can be used to carry out reservoir, economic, environmental, and financial evaluations for steam-based EOR projects. The tool can be used for project appraisal and/or production optimization.

- To provide critical discussions, and in some cases performance evaluations, of various energy sources that have the potential to supply steam for S-EOR projects.

- To illustrate the benefit of the proposed approach through selected case studies.

In order to achieve this objective, an integrated multidisciplinary decision-making tool has been developed. The tool is made up of subsurface performance, surface performance, economic, environmental, and risk models. The developed tool, referred to as TERM-EOR, is used to carry out two case studies. The first case study is surface-orientated and is devoted to the evaluation of cogeneration schemes for S-EOR projects. The second case study is subsurface- orientated where TERM-EOR is used to optimize the steam injection pressure for a particular type of thermal EOR process.

1.8 Thesis Structure

This thesis is organised in eight chapters. This section gives an overview of each chapter.

In Chapter Two an overview of the most common S-EOR methods used today is given. General introduction about the thermodynamic properties of steam that are relevant to S-EOR projects are presented. Typical energy requirements in S-EOR projects and the factors that influence them are also discussed.

In Chapter Three the main objective is to estimate, through thermodynamic simulations, the range of fuel consumption and CO_2 emissions of a typical S-EOR operation.

In Chapter Four, the case for solar energy as an alternative to natural gas in S-EOR projects is discussed and evaluated. The chapter also includes a detailed discussion on the major factors that have prevented the nuclear energy from being adopted by heavy oil developers.

In Chapter Five the research methodology is explained and then the architecture of the proposed integrated framework is presented. Descriptions of the sub-models are given and the governing equations and required inputs are presented.

Chapter Six describes the first case study. TERM-EOR is used to evaluate the potential cost saving and emissions reduction that can be achieved by integrating cogeneration schemes into heavy oil extraction. The project economics is evaluated with and without incorporating cogeneration.

Chapter Seven describes the second case study where TERM-EOR is used to describe the complex integration of various, surface, subsurface, economic, and fiscal parameters associated with process of selecting optimum operating pressure for SAGD projects.

Chapter Eight includes the main conclusions and future work.

2 Fundamentals of Thermal EOR

2.1 Introduction

The recovery of heavy oil is an energy-intensive process that requires large quantities of heat to be injected into the subsurface formation to heat highly viscous oil, reducing its viscosity and, in some cases, providing drive energy to push the heated oil toward production wells. Hot water and steam are both excellent heat carriers but steam is dominantly used in thermal EOR projects. To fully realize why steam is effective in the extraction of viscous oil, one needs to understand the properties of steam as well as what happens in a reservoir when steam is injected. This chapter provides overviews of the most widely used S-EOR processes and the relevant steam properties.

2.2 Thermodynamic Properties of Steam

Steam is an ideal fluid for adding heat into a reservoir because of its high heat content per unit mass. For example, water at 4 barg and 152° C contains 640 kJ/kg, but saturated steam at 4 barg and 152° C contains 2749 kJ/kg, or over four times the heat content of water. This means that for an equivalent amount of heat, steam introduces less water into the reservoir, resulting in less water being produced with the oil and as a consequence more heat remains in the reservoir.

There are a number of steam properties that are of a particular importance in S-EOR operations. These properties are discussed in this section.

2.2.1 Enthalpy

Enthalpy is a measure of the heat content of a fluid. When 1 kg of water at an initial temperature (T_i) is heated at a constant pressure (P_s), it will attain a maximum temperature called saturation temperature (T_s) before it is converted into steam. The amount of heat absorbed by the water during this processes is called sensible heat (h_f). The amount of heat absorbed by the water (h_f) is given by:

Where C_w is the specific heat of water (kJ/kg K)

If water at T_s is further heated at the same constant pressure, it continues to absorb heat without changing its temperature until it is completely converted into steam (*dry steam*). The energy required to evaporate the water at a temperature and pressure of T_s and P_s, respectively, is called latent heat of steam or enthalpy of evaporation (h_{fg}). The heat content of dry steam (h_s) at T_s is given by:

This is simply the sum of sensible heat (h_f) and latent heat (h_{fg}). If the amount of heat supplied to the water at the saturation temperature (T_s) is only a fraction (x) of the total latent heat (h_{fg}), only a fraction of the water is converted into steam i.e. water and steam coexist as a mixture. In this case, steam is referred to as *wet steam*. The total enthalpy (kJ/kg) of wet steam is calculated by:

Where x is the quality of wet steam

Steam quality is simply an indication of the degree of dryness of steam. It ranges from (x=0) for saturated liquid water to (x=100%) for dry saturated steam. An 80% quality steam, for example, refers to a steam water mixture containing 80% steam and 20% water by weight. An equivalent term for steam quality, sometimes used in thermodynamic textbooks, is dryness fraction. Steam dryness is described in terms of a fraction ranging from 0 to 1.

Selected properties of saturated steam for a pressure range from 1 to 70 bar (absolute) are listed in Table 2-1. Enthalpy-temperature relationship of saturated steam is shown in Figure 2-1 with several constant pressure evaporation lines are indicated (dashed lines).

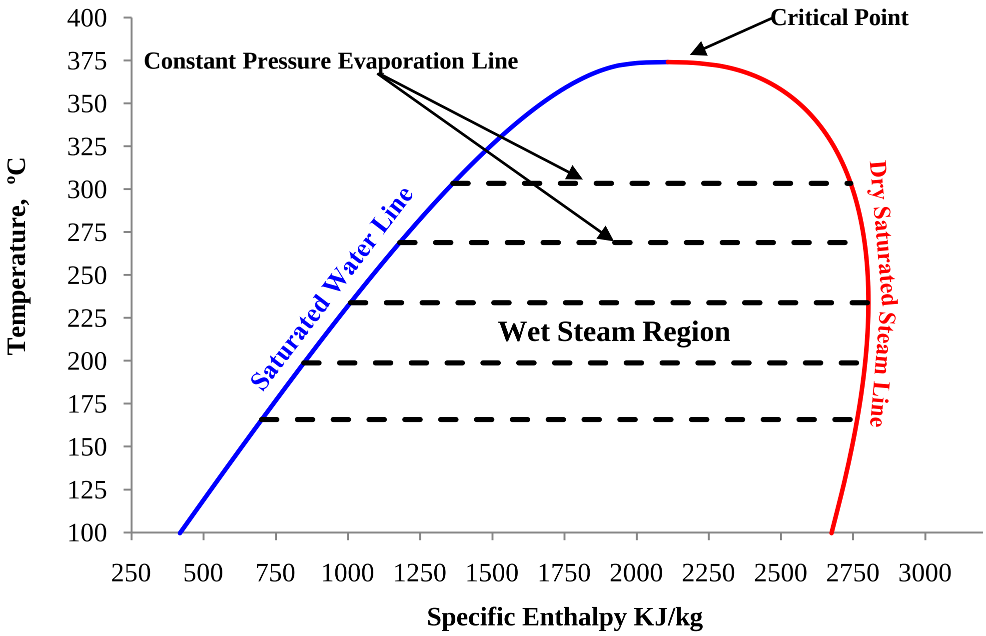


Figure 2-1: Enthalpy-temperature saturated steam chart

Table 2-1: Saturated steam Properties

Absolute Pressure (bara)	Saturation Temperature T_s(°C)	Specific Enthalpy KJ/Kg		
		Water (h_f)	Evaporation (h_{fg})	Steam(h_g)
1	100	418	2258	2675
5	152	640	2108	2749
10	180	763	2015	2778
15	198	845	1947	2792
20	212	909	1890	2799
25	224	962	1840	2802
30	234	1008	1795	2803
35	243	1050	1753	2803
40	250	1087	1713	2801
45	257	1122	1676	2798
50	264	1154	1640	2794
55	270	1185	1605	2789
60	276	1213	1571	2784
65	281	1241	1537	2778
70	286	1267	1505	2772

The effect of steam quality on steam enthalpy is easy to understand. The higher the steam quality, the higher the enthalpy content of steam. For example, the enthalpy of saturated water (*x=0*) at 70 barg and 287 °C is about 1272 kJ/kg; the enthalpy at 50% quality is about 2051 kJ/kg, and the enthalpy at 100% quality is 2770 kJ/kg. In this case, the enthalpy content of the steam has increased by more than two fold simply by moving to higher steam quality.

The impact of steam pressure on saturated steam enthalpy is, however, less obvious. Consider, for example, what happen to steam temperature and steam enthalpy as the steam pressure increases, see Figure 2-2. It can be seen that saturation temperature increases with increasing pressure. However, the rate of increase is greatest at lower pressure. For example, when steam pressure increases from 10 to 30 bar, the corresponding saturation temperature increases by 54 °C whereas only 22 °C increase in saturation temperature is obtained by moving from 50 to 70 bar. It can also be seen from Figure 2-2 that steam enthalpy initially increases with increasing steam pressure until it peaks at about 30 bar, above which the enthalpy starts to decrease. In the context of S-EOR, this implies that injecting steam at pressures above 30 bar, although provides higher operating temperatures, introduces less heat into the reservoir per unit mass of steam.

For reasons discussed in section 2.5, the ratio of latent to sensible heat is also an important consideration in S-EOR processes. Referring to Table 2-1, it is clear that the latent heat (h_{fg}) decreases with increasing steam pressure and thus it is larger at lower pressures. The latent heat becomes zero at the critical point of water, see Figure 2-1. On the other hand, the sensible heat (h_f) increases with increasing pressure and it becomes dominant at higher steam pressure.

While high saturation temperatures associated with high steam pressures are advantageous in terms of viscosity reduction, this advantage has to be weighed against lower total enthalpies and latent heat contents at high pressures. The balance requires rigorous surface-subsurface and economics evaluations as will be demonstrated in Chapter Seven of this thesis.

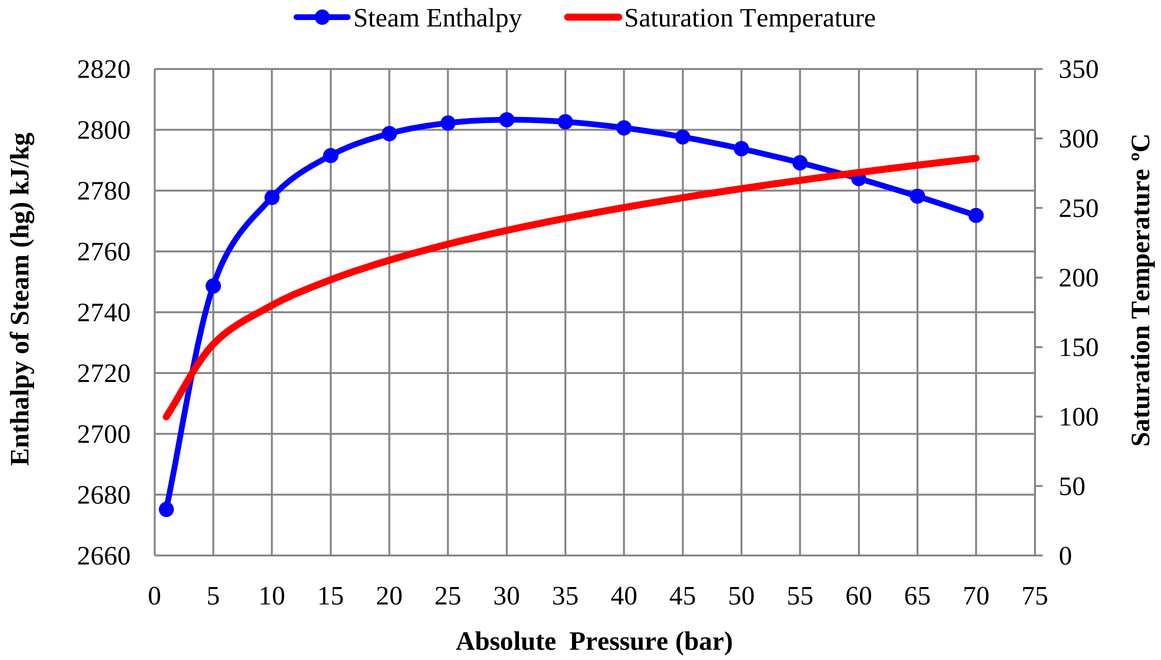


Figure 2-2: Saturated steam temperature and enthalpy as a function of pressure

2.2.2 Specific Volume of Steam

The specific volume of steam (υ) decreases as pressure increases. The specific volume for wet steam can be calculated based on the following relationship:

Where: υ_f = saturated liquid volume in m^3/kg

υ_g= saturated steam volume, m^3/kg

x = steam quality

dry saturated steam (x=100%) at saturation pressure of 24 barg, for example, has a specific volume of 0.08 m3/kg, whereas dry saturated steam at 70 barg has a specific volume of 0.027 m3/kg, almost three fold change in volume. Hong (1994) indicated that the large steam volumes associated with low pressure will result in larger steam zone being developed in the reservoir. As a result, larger proportion of the reservoir will be heated which improves the sweep efficiency of the oil recovery process.

2.3 Basics of Steam Injection

The primary function of thermal EOR is to increase the reservoir temperature. When steam is injected into a reservoir, heat is liberated as steam condenses back to water. This is because the evaporation of water is a reversible process i.e. the latent heat absorbed by the steam during phase change is given out as steam contacts surfaces, such as oil formations, at lower temperatures.

Increasing reservoir temperature reduces the viscosity of the oil in-place, making it more “flowable’’ in the reservoir rock. In some circumstances, injected steam also provides a drive force that aids the heated oil to flow toward production wells. Atypical viscosity-temperature relationship for heavy oil is shown in Figure 2-3.

It can also be seen from Figure 2-3 that the rate of viscosity reduction is greatest at lower temperatures and that the advantage of heat injection starts to diminish at elevated temperatures.

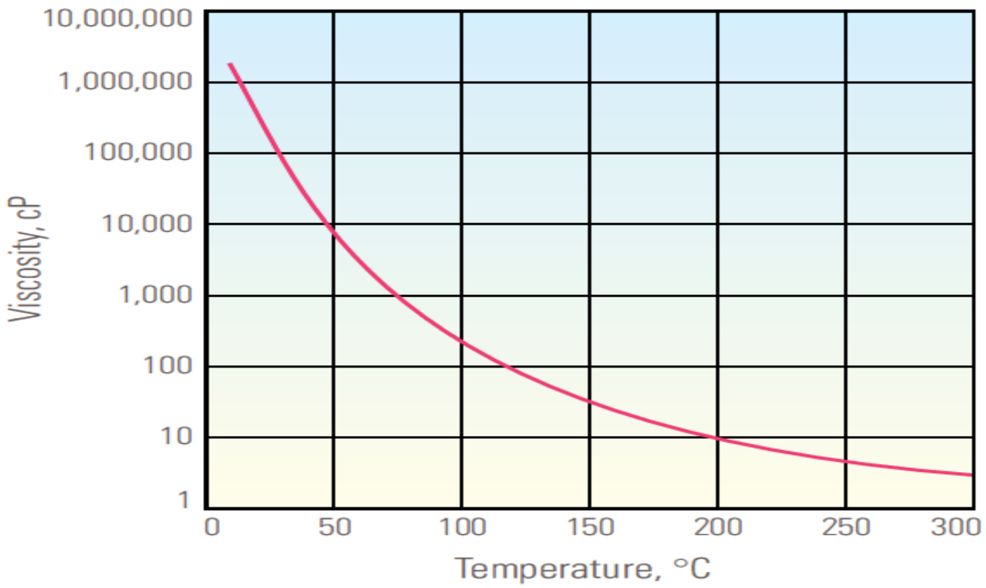


Figure 2-3: A typical viscosity-temperature cure for heavy crude (Hussein, et al., 2006)

2.4 Steam Based EOR Methods

There are three basic types of S-EOR being used today. Cyclic Steam Stimulation, Steamflooding, and Steam Assisted Gravity Drainage. An overview of these processes is given in this section.

2.4.1 Cyclic Steam Stimulation

Cyclic steam Stimulation (CSS), also known as huff-and-puff or steam soak, involves the transfer of heat to reservoir by periodical injection of steam into a production well to reduce the in-situ oil viscosity and thereby improve its mobility (Hong, 1994). CSS is particularly successful for recovering highly viscous oils and bitumen (Michael, 1986) (Butler, 1991).

In CSS projects, steam is initially injected into a reservoir over a period of several days or weeks. The injection well is then shut-in to permit the soaking of the reservoir by the injected steam. The well is then put back on production to allow for the hot oil/water mixture to be pumped out for somewhat longer periods. When oil production declines to a point where oil is no longer produced at economical rates, the whole cycle is repeated. A complete CSS cycle is illustrated in Figure 2-4.

CSS operation tends to become less efficient as the number of cycle increases; with oil production declining with each subsequent cycle. The cyclic process is continued until the quantity of the oil recovered is no longer sufficient to justify further steaming.

In addition to its effectiveness in stimulating very viscous crudes, CSS is also preferred for economic reasons. A single well is used for injecting steam and then producing fluids; thus reducing capital requirement. Furthermore, since steam injection into any well lasts only few days or weeks while oil production lasts several months, portable steam generators can be used (Michael, 1986). In this case, capital cost is reduced further by using portable steam generators that can be moved from one well to another.

The main drawback of CSS is that it typically yields low ultimate oil recovery, ranging from 3-15% of the oil- in-place (Sarathi, et al., 1992) (Hong, 1993) (Farouq, 2008). This is mainly due to the fact that in CSS operations steam can only penetrate and sweep oil within limited radius around the production well. In addition, relatively little drive force is available to move the heated fluids toward the wellbore (Butler, 1994).

The Cold Lake field in Alberta, producing 140,000-150,000 bopd, is an example of CSS projects. The operator of the field, Imperial Oil Ltd's, claims that the field has produced more than 1 billion bbl and that the best years for the field are still ahead (Guntis, 2010).

Ultimate oil recoveries of continuous steam injection are generally higher than those from CCS (Michael, 1986). For this reason CSS is typically followed by continuous steam injection. This is an attractive combination in that oil production is accelerated, due early cyclic stimulation of the well while at the same time the ultimate recovery is improved by continuously injecting steam.

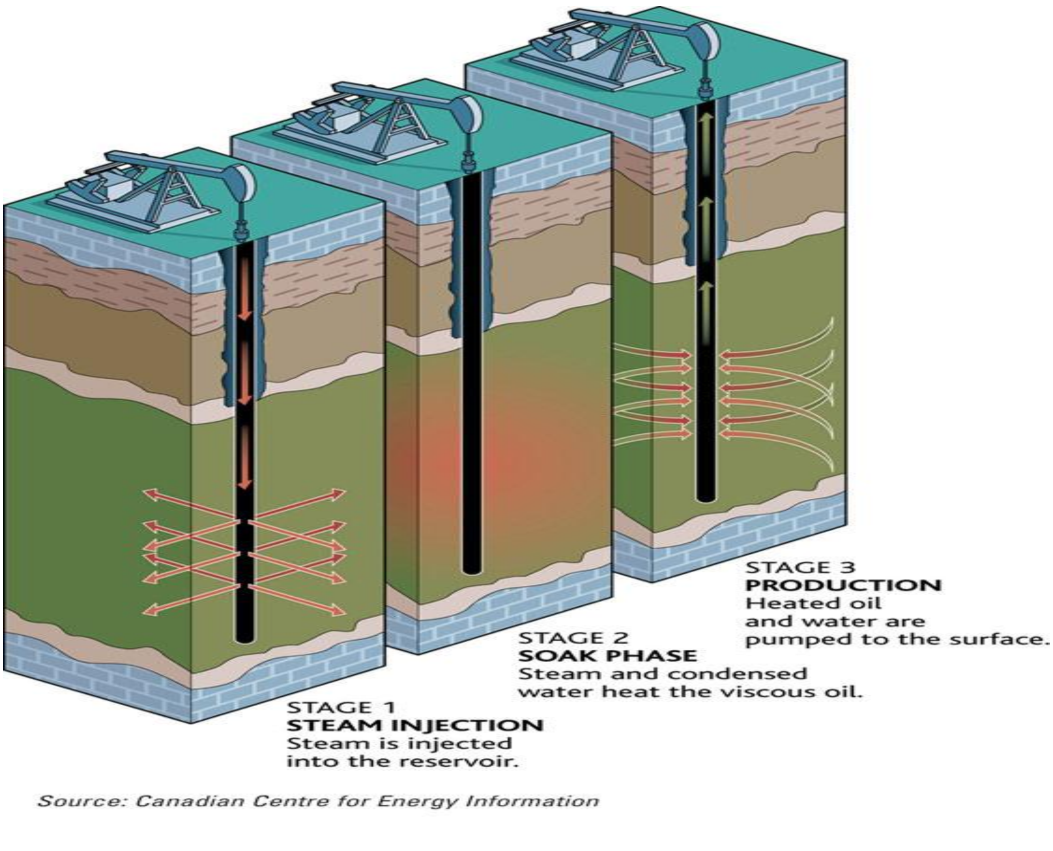


Figure 2-4: CSS production cycles

2.4.2 Continuous Steam Injection- Steamflooding

More sophisticated and difficult than CSS is a technique known as steamflooding. The steamflooding process is also referred to as steam drive. Beside its role in reducing the oil viscosity, the injected steam drives the oil sideways toward production wells, see Figure 2-5. In contrast to CSS, this injection technique uses separate injection and oil production wells, allowing a larger portion of the reservoir to be steamed; and thus results in higher oil rate and improved ultimate oil recovery (Hong, 1993). In California S-EOR operations, for example, the general experience is that higher thermal efficiencies are achieved with CSS but with relatively low overall recoveries. In contrast, higher recoveries are obtained with steamflooding (up to 40%), but at the expanses of larger steam consumptions (Butler, 1980).

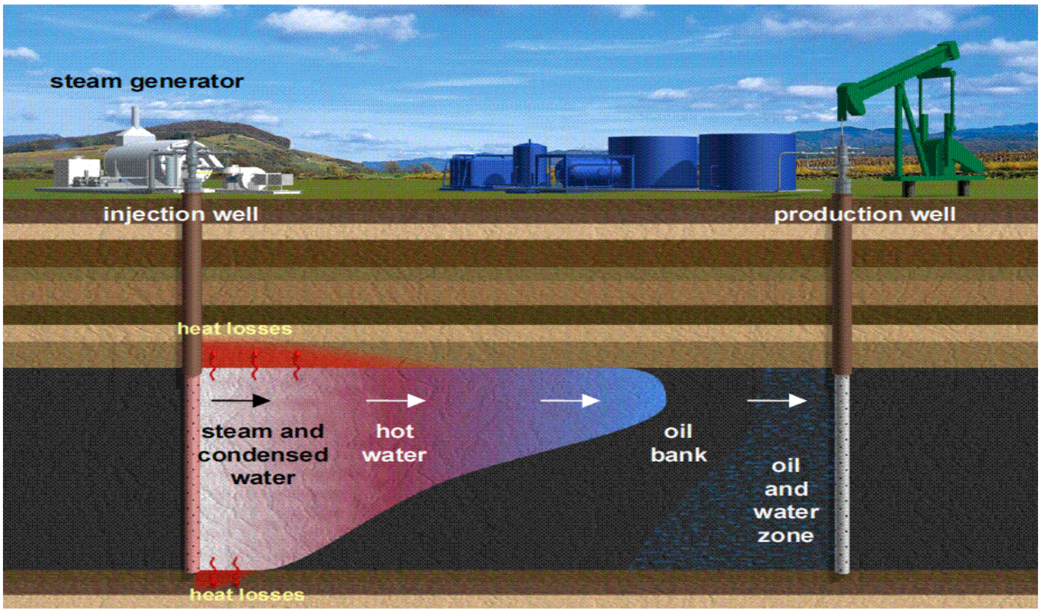


Figure 2-5: Steamflooding process (***image courtesy of Shell)***

Examples of steamflooding operation are the Kern River field in California and the Duri field in Indonesia. The latter is the world's largest EOR project with a production level of 190,000 bopd as in 2008, (Guntis, 2008).

A major drawback to steamflooding is phenomenon known as steam gravity override. This phenomenon is particularly important in thick reservoirs with good vertical communication (permeability) (Kumar, et al., 1993). Driven by strong gravitational gradients imposed by marked difference in density between the injected steam and the reservoir fluids, steam tends to mitigate upwards to the top of the formation, bypassing the oil below (see Figure 2-5). This leads to an early steam breakthrough where much of the injected steam is produced thought production wells without heating much of the reservoir. This results in a dramatic reduction in steam utilization that would negatively impact the project economics.

Fluid breakthrough can also cause a dramatic loss of driving pressure and a marked reduction in oil production (Butler, 1980). The rate of upward mitigation depends on several factors including reservoir thickness, crude oil viscosity at steam temperature and reservoir permeability (Doscher, et al., 1983) (Kumar, et al., 1993). Injection rate is typically reduced after the onset of steam breakthrough to improve steam utilization and project economics.

2.4.3 Steam Assisted Gravity Drainage SAGD

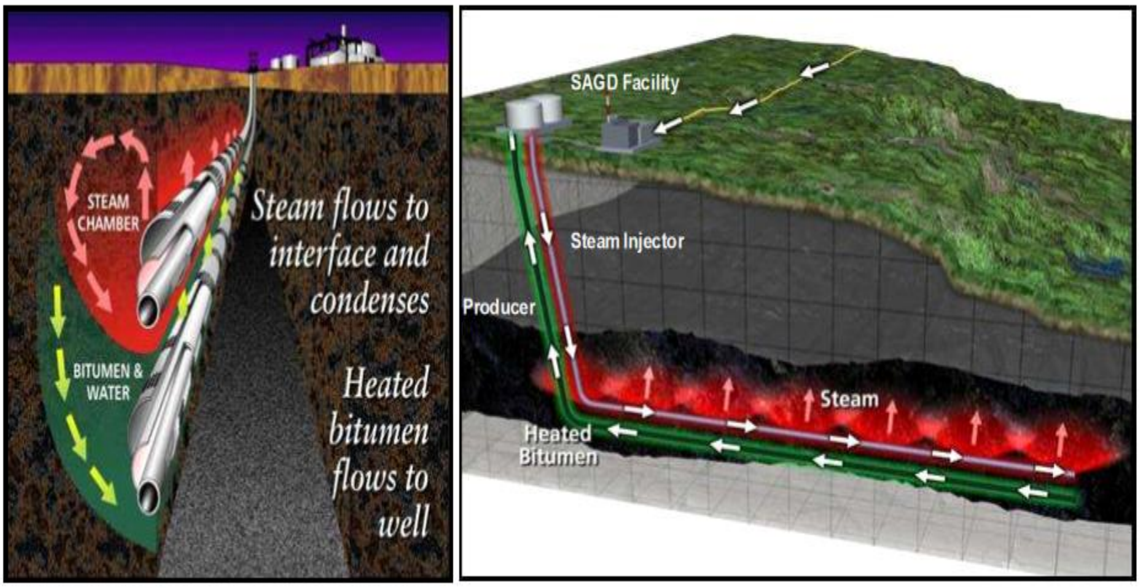
The in-situ viscosities of some types of oils such as the bitumen found in the Canadian Oil sands are so high that almost all conventional production methods are impractical. The bitumen is essentially immobile under reservoir conditions and therefore the injection of any fluids is usually very difficult. CSS was, until recently, the only viable in-situ recovery method of recovering bitumen from the Oil Sands .A major difficulty encountered when applying steamflooding and CSS is that even if the bitumen is heated, there is often insufficient dive available to move the heated fluids to production wells (Butler, 1994) and that communication between the injection and production wells is extremely poor (Reis, 1992). The heated bitumen tends to cool and regain its lost viscosity on its way through the cold reservoir to production well, which prevents adequate oil flows from being obtained.

SAGD (pronounced “sag-dee”) is a special form of steamflooding that was originally developed for the recovery of bitumen. Roger Butler, from Imperial Oil, is recognized as the inventor of this process and his original work was patented (Butler, 1980). The main distinguishing character of SAGD process is the use a pair of parallel horizontal wells, typically located 5 meters apart (Nasr, et al., 2005).

Figure 2-6 is a conceptual representation of the mechanism by which the process proceeds and the general flow within the reservoir. Steam is injected continuously into the upper well, while oil and associated condense water are continuously drawn from the lower well. Butler explained that if steam is injected above but close to the production well, the injected steam would tend to rise and the heavier condensate and heated oil would fall to the bottom. Gravity causes the heated oil to flow down toward the lower horizontal well and hence the name gravity-drainage. The MacKay River and Christina Lake in Canada are example of SAGD application.

The theory that predicts the rate at which this process will occur has been described in a series of papers (Butler, 1980)(Butler, 1991) (Butler, 1994). Some of the main features of SAGD include (Butler, 1991):

- high recoveries can be obtained; 50-70% (Hussein, et al., 2006).
- typically more efficient than conventional steamflooding i.e. less steam is required per barrel of oil produced.
- unlike conventional steamflooding, once the oil is heated it remains hot as it drains to the production well. This allows the process to be used for the heavies bitumen without the need of extensive preheating



Source: Canadian Heavy Oil Association / Suncor Energy

Figure 2-6: SAGD process

2.5 Steam Requirements of S-EOR Methods

Steam requirements for S-EOR operations are typically determined in three steps. In the first, appropriate steam conditions (pressure, temperature, and quality) are selected. Later, the amount of steam (at the predetermined conditions) needed to produce a barrel of oil is obtained using analytical or/and numerical simulators. Finally, the total steam rate and the injection profile are determined to fit with the field size and the proposed development plan.

The characteristics of steam injection profile in S-EOR operations, although is influenced by a number of subsurface, surface and economic factors, has been traditionally discussed from subsurface point of view. The lack of information about the characteristics and economics of surface facilities during the early development phases, combined with under-appreciation among reservoir engineers of the impacts of their decisions on the design and operations of surface facility, means that preliminary evaluations typically focus on maximizing oil rate and not to optimize long run. Under these circumstances, reservoir engineers have no option but to opt for the steam profile that optimizes subsurface performance, which may not coincide with what optimizes overall economics, as will be demonstrated in Chapters Six and Seven.

Selecting an appropriate surface steam technology requires a good knowledge of the characteristics of the steam load. For optimum operation, steam capability and operating characteristics of the selected technology have to match those required by the oil field. A basic understanding of the factors that influence the injected steam conditions and the steam rate is therefore important.

The various steps involved in the determinations of the steam loads for S-EOR projects and the main factors that influence them are discussed in the following sections. The material presented hereafter is used to support further discussions throughout the thesis.

2.5.1 Steam Conditions

Injected steam conditions are primarily dictated by the oil reservoir characteristics. Injection pressure is typically the first steam property to be known and fixed because it is limited within two thresholds. In the lower limit, the injected steam pressure must be higher than the reservoir pressure so that steam can overcome the flow resistance within the reservoir, and thus obtain an acceptable steam injectivity. The upper limit is the formation fracture pressure[8]. If steam is injected over fracture pressure; fractures may be formed in the formation, leading to steam channelling and decrease in recovery performance (Bao, et al., 1998). Steam injection pressure varies widely from one field to another, with as high as 172 barg being reported in the literature (Rodden, et al., 1981). Because only saturated steam is used in S-EOR projects, the selected steam pressure also determines the injected steam temperature.

Once the injection pressure is determined, an appropriate steam quality is selected. It is widely acknowledged that reservoir heating is primarily attributed to the latent heat (vapour) content of the injected steam whereas the sensible heat (liquid) has little or, in some cases, no value in terms of oil recovery. SAGD is an example where, due to its unique oil recovery mechanism and wells configuration, only the latent heat of the steam is utilized. If wet steam is injected, the liquid water fraction of the injected steam would simply fall straight into the horizontal producer well located few meter above the steam injector, see Figure 2-6. This does not contribute to the oil recovery and, in fact, adds to water recycling costs. It is for this reason the injection of less than 100% quality steam in SAGD projects is considered counterproductive since (Scott, 2002).

The task of determining an optimum steam quality for steamflood and CSS projects is more complex. Both forms of heat (latent and sensible) are believed to contribute to reservoir heating but to varying degrees (Hong, 1994). The form of energy dictates the efficiency of the oil recovery process as well as the effectiveness of various mechanisms responsible for the oil production (Kimber, et al., 1995).

[8] In some unique applications steam is intentionally injected at pressure above the facture pressure in order to establish heat and fluid communication between the injectors and producers to accelerate production response, improve sweep efficiency , and reduce the heat losses

Theoretically speaking, the higher the latent heat content of the injected steam the better the oil recovery process is. Hong (1994) carried out a comprehensive study to evaluate the performance of steamflood at different steam qualities and injection rates. He indicated that for a typical heavy oil field, steamflood performance improves monotonically with increase in steam quality and injection rate. However, when economic factors such as fuel consumption were factored in, the optimum steam quality was found to be much lower than what was previously thought. Additional oil recovery associated with higher steam qualities has to be weighed against additional fuel need to generate higher quality steam. In keeping with this conclusion, Hong recommended that the steam quality should be selected based on economic indicators rather than simply being based on the resulting oil profile.

Despite the uncertainties, steam quality in the range 70-80% is dominantly used in CSS and steamflood projects. This range, however, is not necessary an optimum from subsurface point of view as it is widely misunderstood. It is rather a maximum steam quality that oil-field steam generators can attains for reasons explained in section 2.6.

2.5.2 Steam Consumption

Steam to oil ratio (SOR) is a parameter commonly used in S-EOR projects to describe the steam consumption of the recovery process. It is simply a measure of the volume of water required to be converted into steam, at the predetermined conditions, and then injected to produce one unit volume of oil. SOR is a critical techno-economic parameter in S-EOR evaluation because it gives an indication of the efficiency of the recovery process. The field SOR affects the amount of water consumption, surface fuel consumption, and GHG emissions associated with producing a barrel of oil.

The SOR varies widely. In California oil fields, for example, SOR varies from an efficient 2.47 barrels of steam per barrel of oil at Kern River field, to a less efficient 8.43 at Kern Front field (Stevens, et al., 1999). One important variable is the technique used i.e. CSS, steamflood, or SAGD. As mentioned in Section 2.4, CSS tends to use less steam than steamflood and SAGD because it injects steam intermittently and is typically applied to new field where recovery is less difficult that after the recovery has been going on for a period of time (Rodden, et al., 1981). Another important variable is the depth of the reservoir. Because the heat losses in the steam delivery network (surface steam pipes and wellbores) as the depth of the reservoir increase, more steam will be required for deep reservoirs than shallow reservoirs.

One large variation lies in the maturity of the recovery process i.e. the length of time that steaming has been going on in a given reservoir. The SOR profile is typically high at early injection stages where relatively large proportion of the injected heat is lost through steam delivery networks and to reservoir's adjacent formations (Michael 1986). During intermediate stages the profile tends to stabilize before it starts to deteriorate again at latter stages as the reservoir depletes; thus larger proportional of the injected heat is lost through produced fluids. In theory, the SOR can go to infinity. Economics and environmental constraints, however, require that the field SOR to be minimized and in many cases capped. This is because there is always a cut-off SOR value where the economic value of the produced oil is less than the cost of producing it.

2.5.3 Steam Profile

Once the required steam conditions and the resultant SOR profile are known, the field daily steam rate is determined based on the field size. Another factor that influences the steam profile is the field development plan. Staged development approach is typically adopted in S-EOR projects in an effort to minimize geological, engineering, and financial risks associated with these types of oil developments. In this case, low to moderate steam injection rates are initially considered while the performance of the field is monitored and evaluated. A decision whether to expand the capacity of the operation is then made based on the field performance.

The steam injectivity achievable at early injection stages is typically low, preventing high steam rates from being attained. Steam injectivity tends to improve as a better communication is established between injectors and producers, and as the reservoir pressure starts to decline.

The high cost of steam generation in S-EOR projects necessitates continuous and careful monitoring of the injected heat. It is a common practice within maturing S-EOR projects to reduce the steam injection rate or/and quality in order to improve the process energy utilization, and thus prolonging the project economic life by reducing the surface fuel consumption(Ziegler, et al., 1993) (Hong, 1993)(Messner, 1998).

Adjustment to the steam injection rate may be brought by low oil prices or high natural gas prices where the project economics becomes marginal. For example, the steam injection rate was reduced by 60% for an extended period in Potter field in California promoted by high natural gas prices (Fram, et al., 2002).

2.6 Water Requirements

A large quantity of water is consumed in the generation of steam for S-EOR operations. Depending on the SOR, it can take up to eight barrels of fresh water to produce a barrel of oil. In addition, the quality of feedwater is critical to the successful operation of steam generation equipments and if water treatment cost is to be kept to an acceptable level. Field experience indicates that most steam generator downtime is caused by water treating issues (Partha, et al., 1992). Therefore, successful operation of steam injection projects depends primarily on the ability to provide a good source of feedwater as well as an effective water treatment system.

Feedwater for steam generation is typically sourced through fresh water wells, lakes, rivers, and dams. The availability of fresh water, however, is becoming increasingly scarce in many counties and thus the use of salty water from deep aquifers known as brackish groundwater is becoming more common. In addition, environmental regulations in many places require partial or even total recycling of the produced water for steam generation. To make matter worse, a fraction of the injected steam is lost into rock formations and hence not all of the injected water is recovered.

Given the fact that large quantities of water is required for continuous steam injection, the cost of treating the feedwater for steam generation must be kept as low as possible. Recycled water, after circulating in the ground, and water from brackish sources carries with it considerable quantities of hardness, silica, salinity and various types of dissolved solids. Treating this water to levels where it can be used in conventional steam equipments is a prohibitively expensive task and requires great energy consumption and results in large amounts of wastes being generated as by-products.

As discussed in section 2.5.1, S-EOR processes require steam quality of 100% or less i.e. superheated steam is not used. This unique feature is being utilized by heavy oil producers to reduce water treatment costs while still meeting injection steam requirements. Instead of producing dry-saturated or superheated steam as in the power generation industry, wet steam (typically 75-80% quality steam) is produced using once-through type steam generators (OTSG), see Figure 2-7. It works by maintaining a sufficient liquid in the bulk flow inside the OTSG tubes to ensure a constantly wetted tube surface. The general purpose is that water soluble solids carried in the feedwater stay in the liquid phase of the water/steam mixture and exit the OTSG. The presence of liquid flow will also ensure adequate cooling of the inner OTSG tube walls to keep their metal temperature down at a safe level.

In this case, the quality of the boiler feedwater does not need to be as stringent as that required in conventional steam plants, where dry or even superheated steam is required. In fact, water quality with silica content of up to 100 mg/l and total dissolved solids TDS of up to 12,000 mg/l is considered acceptable for oil field OTSGs (Pedenaud, et al., 2008).The recommended water specification for oil field OTSGs is shown in Table 2-2(Pedenaud, et al., 2008). The exit steam quality dictates the permissible level of various components. The permissbile impurity levels specified in Table 2-2are based on 80% steam quality. Higher levels could be achieved by lowering the exit steam quality further. For reference, the recommened silica and TDS for General Electic (GE) steam turbine is 10 mg/l and 50 mg/l repectively (Carvalho, 2007). For detailed discussions on the design and operation of oil field OTSG see (Fanaritis, et al., 1965)(England, et al., 1984)(Partha, et al., 1992).If dry steam is required as in SAGD operations, the wet steam produced in the OTSG is routed to a downstream high pressure steam separators where the water content of the steam separated to provide relatively dry steam for field injection.

The concept of producing wet steam, although reduces water treatment costs and environmental impacts, adds extra level of complexity to steam plant operation. Accurate and continuous adjustment to the available control inputs is necessary in order to maintain the design exit steam quality. This task is particularly challenging when the heat source for steam generation is erratic such as in the case where gas turbine exhaust is used for steam generation. The heat content of gas turbine exhaust is non-uniform and is influenced by a number of factors including gas turbine load, control strategy, and ambient conditions. This makes the control system more difficult to manage. On the other hand, operating the OTSG above the specified quality limit would cause rapid accumulation of deposits on tubes, potentially resulting premature failures and plant unscheduled shut downs.

Table 2-2: Typical Permissible impurity limits for oilfield OTSG

Component	Permissible Impurity Limit
Total Hardness	<1 mg/l $CaCO_3$
Barium	<0.1 mg/l
Iron	<0.25 mg/l
Free Chlorine	<0.1 mg/l
Oxygen	<0.02 mg/l
Oil	<0.5 mg/l
Silica	<100 mg/l
pH	<7.0-9.0
Total Dissolved Solids	<12,000 mg/l

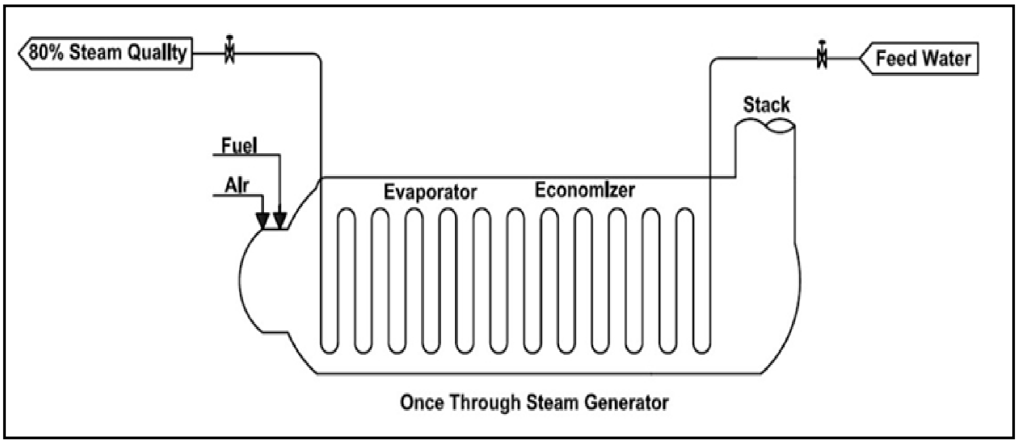


Figure 2-7: Simplified schematic of an oilfield OTSG

2.7 Electricity Requirements

S-EOR operations also require energy in the form of electricity for a variety of functions. The largest consumption of electrical power is for driving pumps that lift produced fluids from the reservoir. Electrical power is also used within the steam facilities for feedwater cleaning and to drive high-pressure boiler feedwater pumps. Electricity consumption in S-EOR operations is little compared to heat consumption, and is reported to range between 9-13 kWh per barrel of oil produced (Stevens, et al., 1999) (Nicole, et al., 2005) (Finan, et al., 2010).

2.8 Discussion and Concluding Remarks

It is evident from the proceeding discussions that steam profiles in S-EOR operations, although do not show diurnal and seasonal variations, are influenced by a number of surface, subsurface and economics and strategic factors. Energy loads in S-EOR have the following main characteristics:

- high energy utilization. S-EOR operations have a year-around demand for steam and electricity, an important economic advantage.
- steam-intensive with little electricity usage, resulting in high heat to power ratio.
- only saturated steam is required i.e. superheated steam is not needed.

These factors that have to be carefully considered while selecting, sizing and designing surface steam facilities. The economic viability of S-EOR projects is primarily governed by the oil recovery rate (subsurface) versus the cost of steam required to recover this oil (surface). Although it is the task of reservoir engineers to decide on the injected steam conditions and steam profile, the decisions they make will greatly influence the selection and operation of surface facilities. Consider, for example, the case of steam injection pressure where higher injection pressures result in high operating temperatures, and thus greater viscosity reduction and oil rate. However, as discussed in section 2.2, the steam pressure will also influence the total enthalpy and the latent heat content of the injected steam, which in turn impact the surface fuel consumption and GHG emissions. Similar argument applies to the case when steam quality is selected. Higher steam qualities are expected to yield higher oil recovery but at the expenses of more fuel consumption and GHG emissions.

The effects of steam conditions on fuel consumption, fuel cost, and CO_2 emission are illustrated in Chapter Three and the impacts of operating pressure on SAGD techno-economic and environmental performance are evaluated in Chapter Seven.

3 Fuel Consumption and CO_2 Emission of S-EOR Projects

3.1 Introduction

The recovery of heavy oil is an energy intensive process that requires both electrical and thermal energy. This energy is typically sourced through fossil fuel conversions. Natural gas, being the preferred fuel option in the oil field, is consumed in large quantities to produce the required steam. A rule-of-thumb commonly used in the industry is that approximately 1,000-1,300 cubic feet of gas is required to produce a barrel of oil through steam injection. Steam for S-EOR operations is typically generated using direct-fired, once-through type steam generators (OTSG), see Figure 3-1.

Energy consumption and CO_2 emissions are major challenges when it comes to S-EOR evaluations. Heavy oil developers have long been seeking ways to cut natural gas consumption and to find alternative fuel options. In order to demonstrate the scale of energy consumption and GHG emissions and to appreciate the need to adopt energy efficiency measures, the objective of this chapter is set to evaluate through thermodynamic simulations the expected range of fuel consumption and CO_2 emissions for a typical S-EOR project.

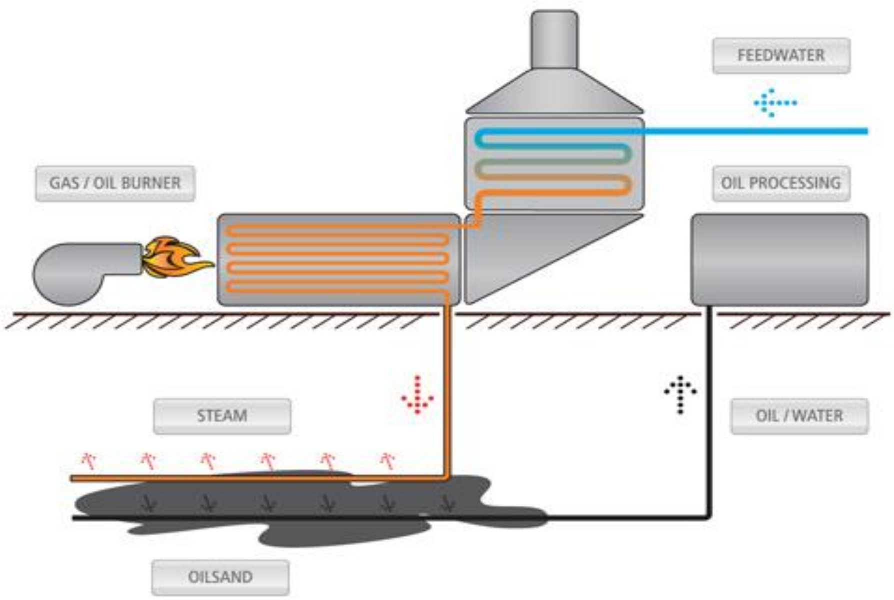


Figure 3-1: A typical S-EOR facilities (*Courtesy of IST)*

3.2 Field Description

A 30,000 bopd project is considered in this chapter and the range of fuel consumption and CO_2 emission at various operating scenarios are evaluated. The baseline steam requirements are shown in Table 3-1. This hypothetical heavy oil field is refereed hereafter as Field-A.

Steam rates in S-EOR projects are normally reported in barrels of steam per day (bspd) regardless of steam pressure and quality i.e. in cold water equivalent (CWE). The CWE rate is simply an equivalent to the mass flow rate and is therefore much smaller than the actual volumetric rate. For consistency, steam rates are reported in CWE throughout this study. Unless otherwise indicated, steam pressure and temperature are reported in bar gauge (barg) and degrees Celsius (°C) respectively.

Table 3-1: Field-A steam requirement

Field Size (b/d)	Pressure (barg)	Temperature (°C)	Quality (%)	Steam Rate, CWE (bspd)	SOR -
30,000	70	287	100	90,000	3

3.3 Process Description and Control

Figure 3-2 is a schematic of the considered steam plant. The layout of the plant is a modified and simplified representation of an actual S-EOR project currently being developed[9]. The plant is modelled using the Thermoflex process simulator of Thermoflow Inc[10]. The main inputs to the simulation are listed in Table 3-2.

The field requires 100% quality steam at 70 barg. This is achieved by first generating 80% quality steam in an OTSG, followed by condensate separation in downstream HP steam separator. Blow-down from HP separator is routed to LP flash tank where more steam is generated at lower pressure (0.21 barg). This deaerator operating pressure is

[9]It is worth noting that although steam rates and conditions considered in this case study are realistic, they are not related to the actual projects.

[10]www.thermoflow.com

typical in steam plant (SpiraxSarco, 2008). The LP steam is used in the deaerator to preheat the incoming feed water to 105 °C. Feed water preheating is required to remove dissolved gases and to prevent corrosion related issues in steam generation equipments. If steam supply from the LP flash tank is not adequate to meet the deaerator full demand, additional steam is let down from the HP steam header but at the expense of less steam being available for field injection. Blowdown from the LP flash tank is passed through a heat exchanger where it exchanges heat with the incoming feed water to raise its temperature before the deaerator. This reduces the amount of steam required for deaeration and thus improves the overall efficiency of the steam plant.

Table 3-2: Thermoflex Simulation main inputs

Steam Generator Efficiency LHV (%)	Feed Water Temperature (°C)	Deaerator Pressure (barg)
92	50	0.21

3.4 Oil Fired Steam Plant

The obvious fuel to use in oil fields is the produced crude. However, crude oil is seldom used in S-EOR operations for two reasons. The first is environmental; the combustion of crude oil produces more GHG emissions compared to natural gas. The main reason is, however, driven by economic factors. Crude oil has been historically a more expensive source of energy per unit energy, see figure 3-3 (BP, 2010). This was particularly apparent in the past five years when oil prices have been unprecedentedly high.

The use of crude oil has a double impact on the projects economics. The use of more expensive fuel results in higher fuel cost and hence to a lower ultimate oil recovery before the economically limiting SOR is reached; thus shortening the project economic life. Secondly a significant proportion of the project’s anticipated oil revenue is lost since the amount of oil available for sale is reduced due to onsite consumption for steam generation.

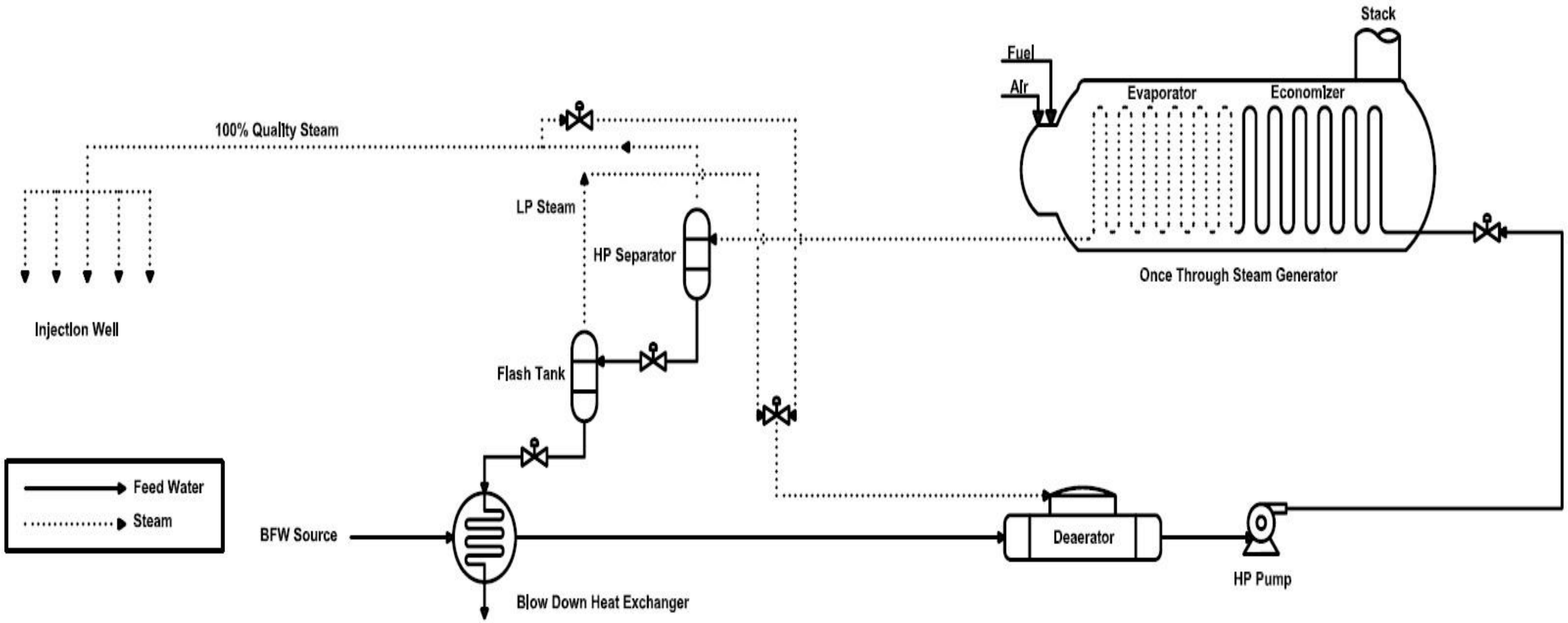


Figure 3-2: schematic of Field-A surface steam facility

The composition of the oil fuel used in the simulation is shown in Table 3-3. The results for the oil-fired steam facility are shown in Figures 3-4 to 3-7. At the baseline assumptions outlined in Table 3-1, Field-A would require 7300 barrel[11] of oil to generate the required steam. This accounts for approximately 25% of the total daily production of 30,000 bopd. In other words, one barrel of oil is burned to produce four barrels of oil, resulting in a net of three barrels of oil. The daily fuel consumption as a function of SOR at varying steam generator efficiency is shown in Figure 3-4.

A more useful representation of the results is to plot the net oil, which is simply the difference between oil produced and oil consumed, see Figure 3-5. At SOR of 9, for example, only 30% of the recoverable crude is available for sale. Figure 3-5 also shows that at steam generator efficiency of 92%, all of the produced oil will be consumed for steam generation if the SOR exceeds 13. In other words, the highest SOR that is tolerable without burning more oil than is produced is 13. This value is even lower, at about SOR of 11, for the less efficient steam generators (η=80%).

The field annual fuel cost as a function of SOR and at different oil prices is shown in Figure 3-6. For the baseline assumptions, Figure 3-6 indicates that at an oil price of $80/bbl fuel cost will account for more than $210MMannually. The actual cost will depend on the field's SOR profile, steam generation efficiency, and fuel prices.

The average CO_2 emission (kg.CO_2/bbl) and the field total annual CO_2 emission are shown in Figures3-7 and 3-8 respectively. At the baseline assumptions, the average CO_2 emission is 110kg.CO_2/bbl; resulting in a cumulative emission of 1200 thousand ton of CO_2 annually. At higher SOR and lower steam generator efficiency (η=80%), CO_2 emissions reaches as high as 250kg.CO_2/bbl.

Table 3-3: Oil fuel compositions

Component	Ash	Carbon	Hydrogen	Oxygen	Nitrogen	Sulphur
Weight %	0.1	85.7	10.5	0.66	0.34	2.7

[11]Based on 5.8 MMBtu/bbl HHV

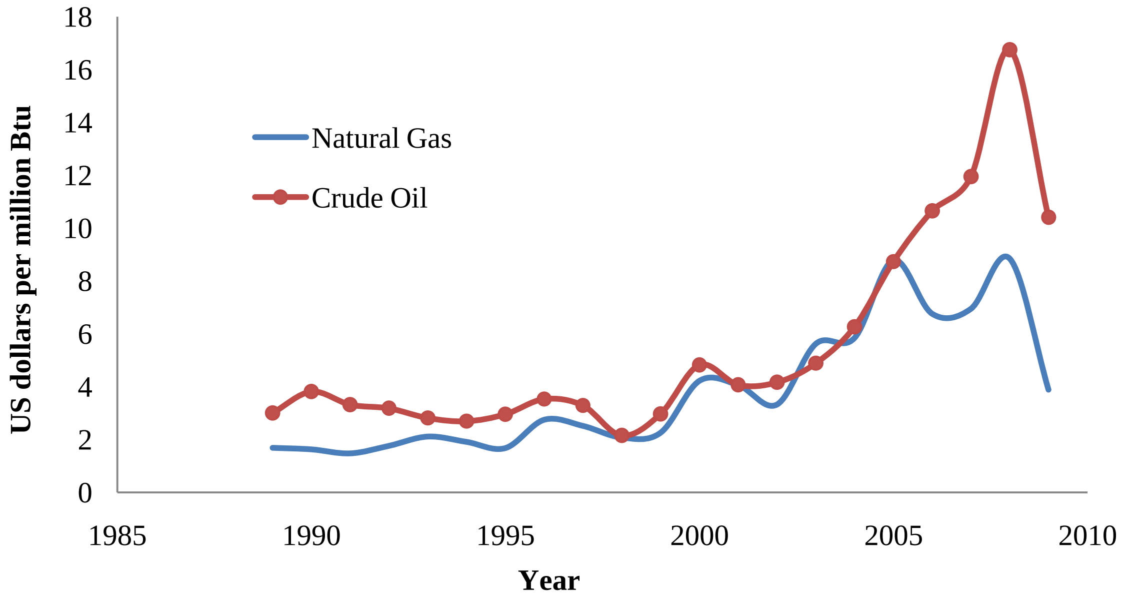


Figure 3-3: Historical crude oil and natural gas prices (BP, 2010)

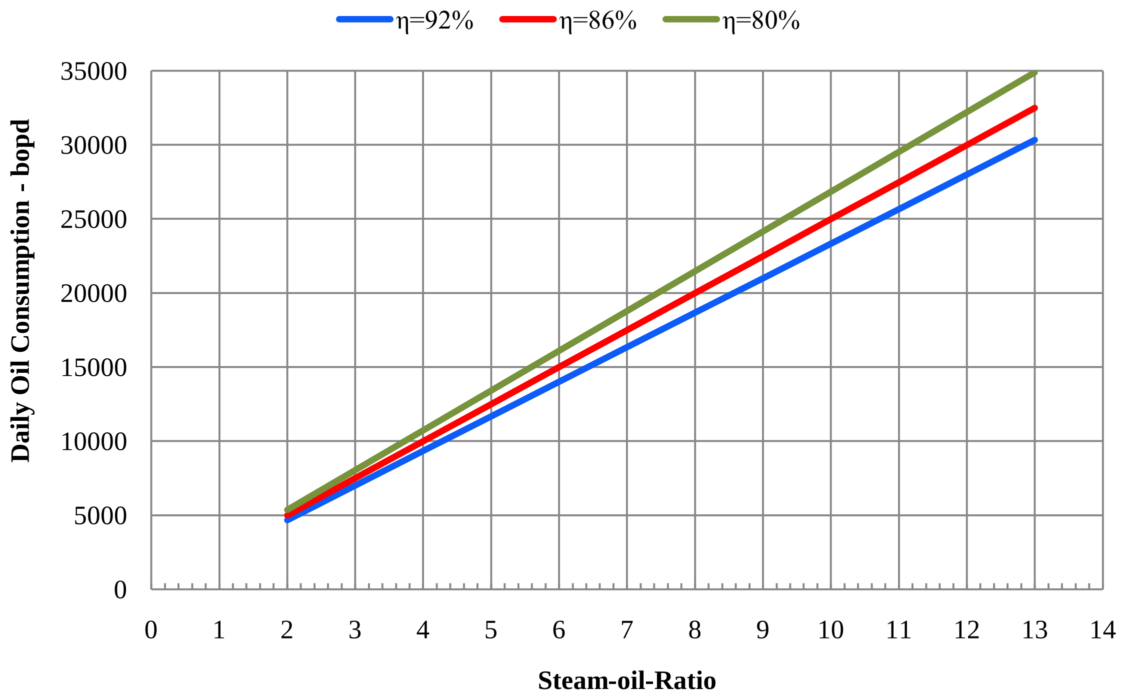


Figure 3-4: Daily oil consumption as a function of SOR

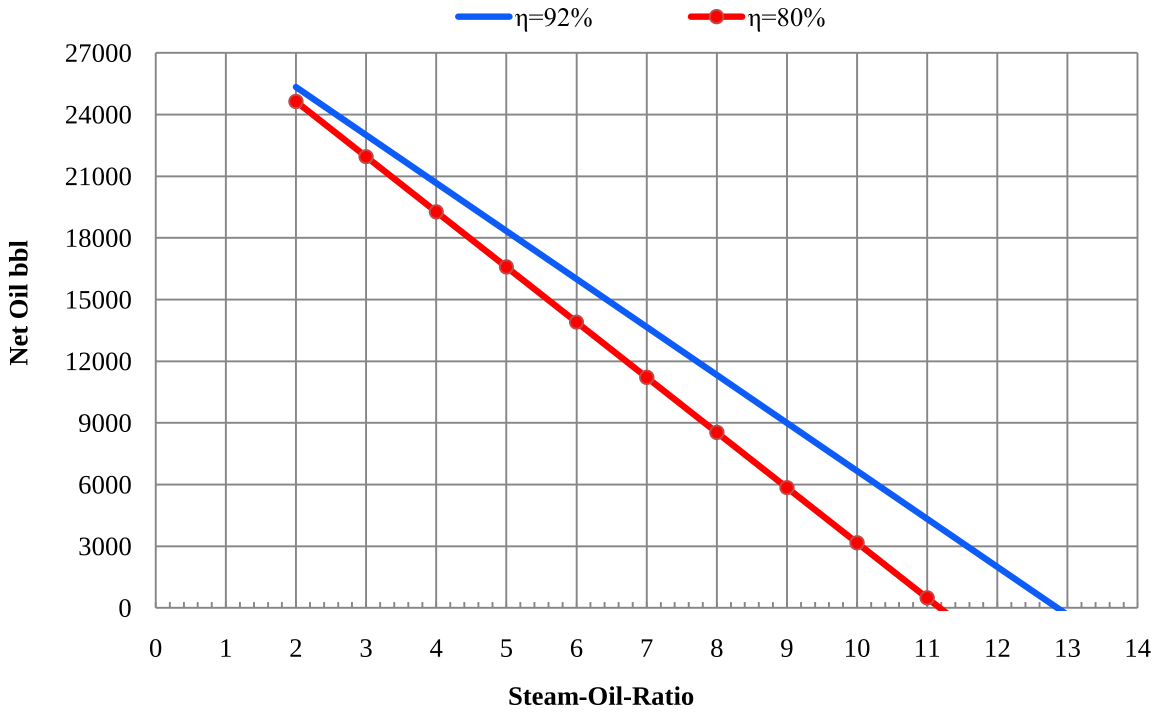


Figure 3-5: Net daily oil consumption of Field-A as a function of SOR

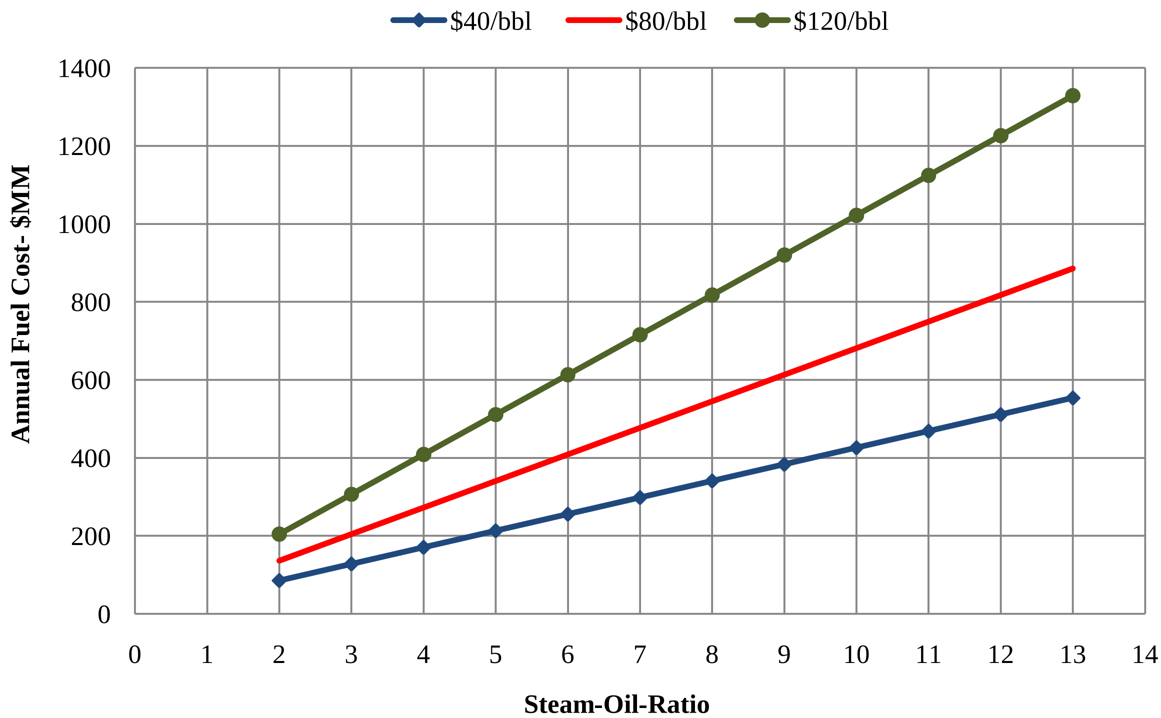


Figure 3-6: Annual fuel cost as a function of SOR and oil price (η=92%)

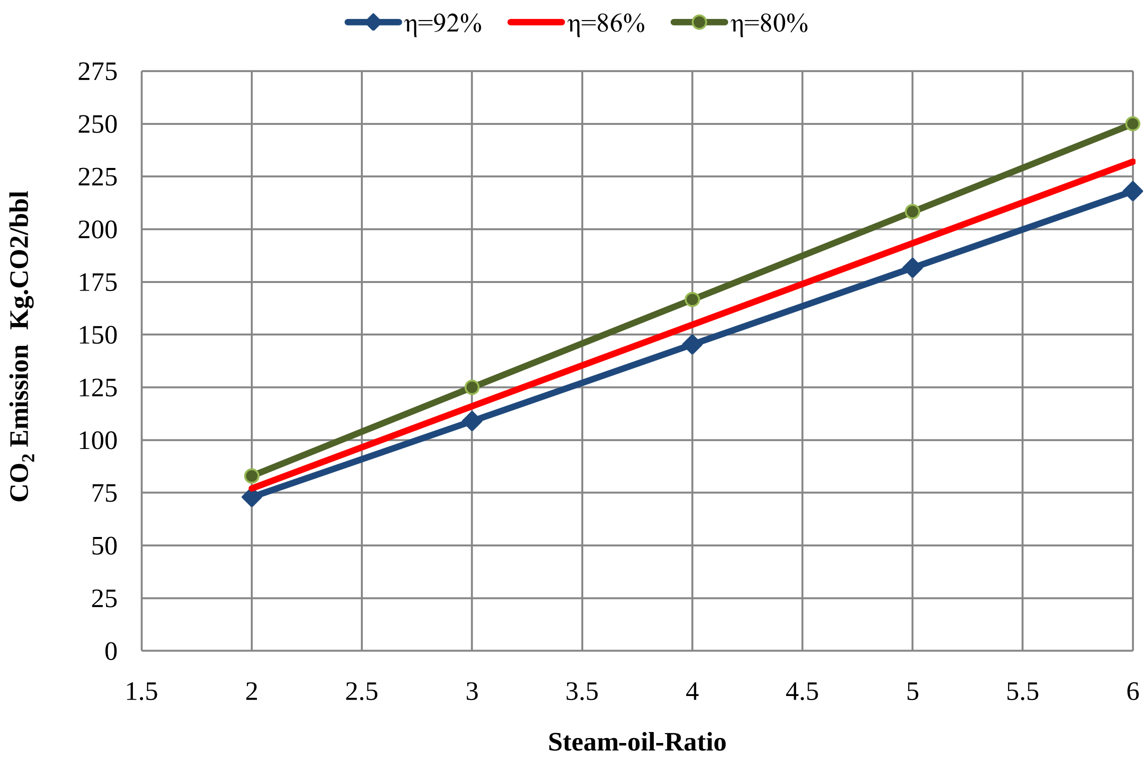


Figure 3-7:CO_2 emission per barrel of oil produced as a function of SOR

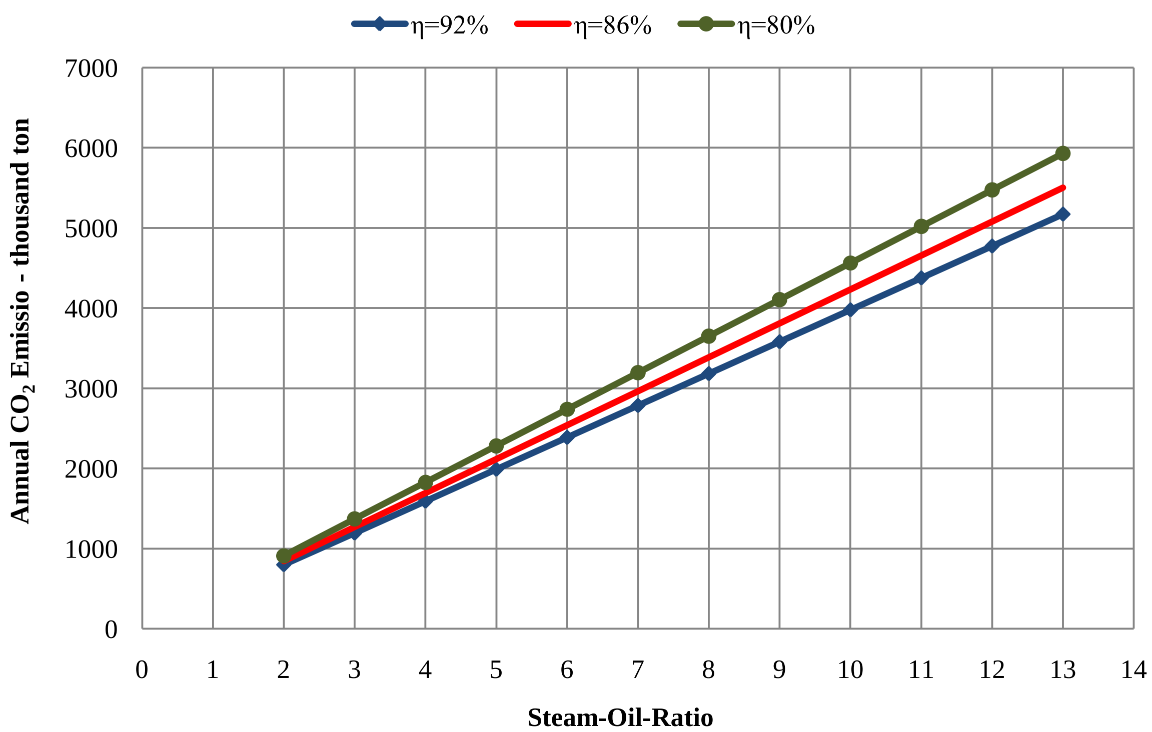


Figure 3-8: The field daily CO_2 emission a function of the SOR

3.5 Natural Gas Fired Steam Plant

Natural gas remains the preferred fuel in oil fields because of its clean burning characteristics compared to other fossil fuels and it is typically produced on-site or within a close proximity to S-EOR activities. A rule-of-thumb commonly used in the industry is that approximately 1,000-1,300 cubic feet of gas is required to produce a barrel of heavy oil through steam injection. To check the validly of this rule-of-thumb and in order to evaluate the various factors that influence natural gas consumption and CO_2 emissions, the steam plant described in Section 3.4 is reconsidered but using natural gas as fuel instead of crude oil. The compositions of the natural gas used in the simulations are shown in Table 3-4.

Table 3-4: Natural gas fuel compositions

Component	CH_4	C_2H_6	C_2H_4	CO_2	CO	O_2	N_2	H_2S	H_2
Volume %	87	8.46	0.03	0.34	0.09	0.07	3.61	0.04	0.36

Figure 3-9 shows the field daily natural gas consumption as a function of SOR. Considering and *optimistic* case of 92% steam generator efficiency and a SOR of 2, the natural gas consumption per barrel of oil is about 920 cubic feet of gas per barrel of oil produced (cf/bbl). As the recovery process matures and the efficiency of the recovery process deteriorates, more energy would be needed to recover a barrel of oil which is reflected in higher SORs. If the SOR rises, for example to 5, fuel consumption increases to as high as 2300 cf/bbl. Such SOR although high but it is not something unheard off. For example, the reported production-weighted-average SOR for California thermal fields was 5.13 in 2006 (Brandt, et al., 2010). At the baseline assumptions outlined in Table 3-1, the daily natural gas consumption is about 41 million cubic feet (MMcf). At natural gas price of \$3.96/MMBtu (\$4.08/Mcf)[12], this will result in annual fuel cost of 61 \$MM. It is worth noting that although this is still considered high operating cost but is about 150 \$MM lower than the corresponding case for the oil fired steam plant. The

[12] This is the average NYMEX natural gas price for January 2011. Price is converted from \$/MMBtu to \$/cf using a HHV of 1029 Btu/cf

economic advantage of using natural gas instead of crude oil is therefore clear. The annual fuel cost as a function natural gas price and at different SOR is shown in Figure 3-10. It can be seen that fuel costs can reach as high as $ 373 million annually at a combination of high natural gas prices and low steam generation efficiency.

The effect of the field SOR on CO_2 emissions is illustrated in Figure 3-11. Depending on the assumed steam generator efficiency as well as the SOR, CO_2 emission varies widely from 50 to 170 kg.CO_2/bbl. For the baseline assumptions, CO_2 emission is 85 kg.CO_2/bbl, which is 25 kg lower than the corresponding oil fired case.

Another important parameter that greatly influences energy consumption is injection steam quality. Figure 3-13 shows the effect of steam quality on natural gas consumption per barrel of oil produced. For example, more than 180 cf of natural gas would be saved for every barrel of oil produced if the field requires 80% quality steam instead of 100%. This equates to 5.4 MMcf/d saving in natural gas for a 30,000 bopd project. At natural gas price of 4 $/Mcf, this would result in about8 $MM worth of annual saving in fuel cost.

There are also a number of surface factors that affect the efficiency of the steam generation process. Beside the generator efficiency illustrated in the proceeding results, the temperature of the feedwater to the steam generator has pronounced impacts of the steam plant overall efficiency. Figure 3-13 shows the effect of feedwater on the steam plant daily fuel consumption. A 50 °C increase in feedwater temperature (from 10 to 60 °C) reduces the daily fuel consumption by more than 3.3 MMcf. In this case, increasing the feedwater temperature has two effects. The first is to utilize the LP blow-down from the flash tank, which would otherwise be recycled and wasted. The second is to use less HP steam in the deaerator. The impact of feedwater temperature on HP extraction is shown in second y-axis of Figure 3-13. It can also be seen that further increase in feedwater temperature above 70 °C has no effect on fuel consumption. This is because at such high temperatures, the LP steam is sufficient to meet the deaerator full requirement. Secondly, it is assumed in this study that the deaerator is operated at 0.21 barg which corresponds to a saturation temperature of 105 °C, limiting the ability to benefit from higher feedwater temperature. Therefore, the deaerator operating pressure may need to be increased if higher feedwater temperature is readily available.

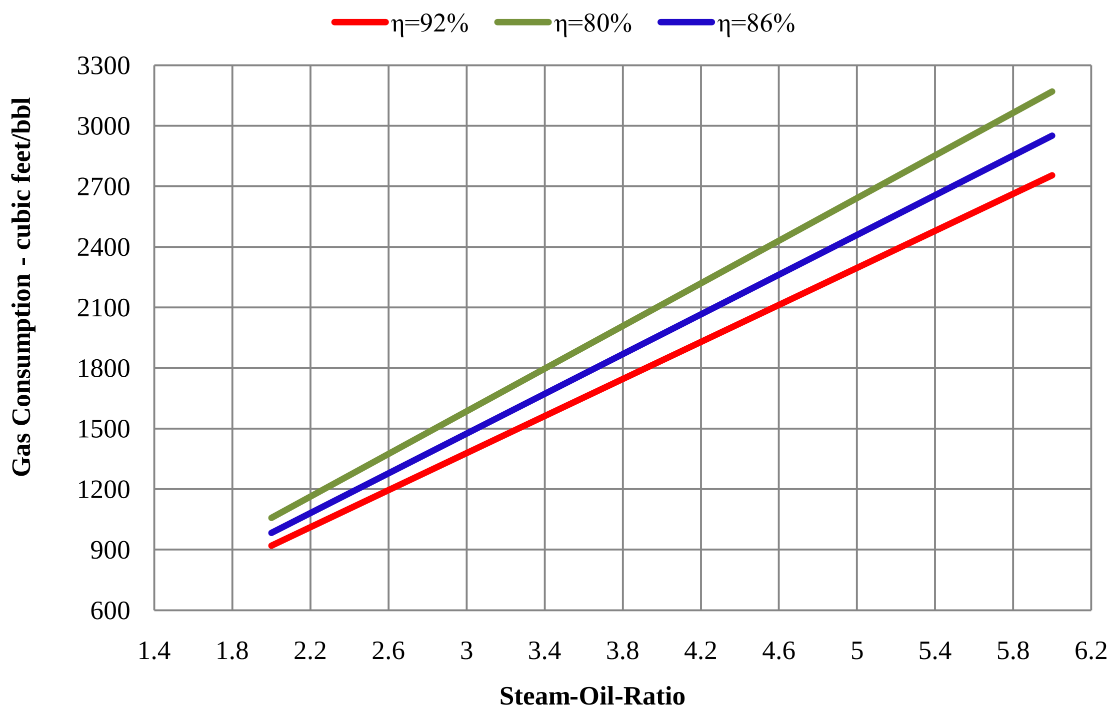


Figure 3-9: Natural gas consumption as a function of SOR

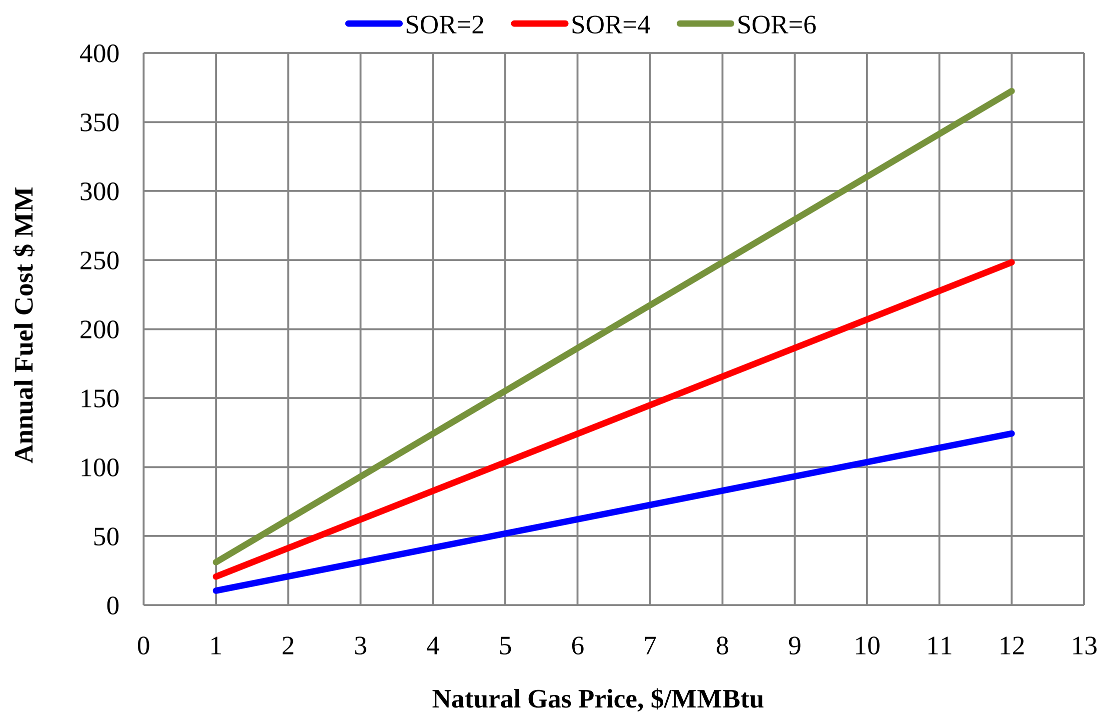


Figure 3-10: Annual fuel cost as a function of SOR and natural gas price

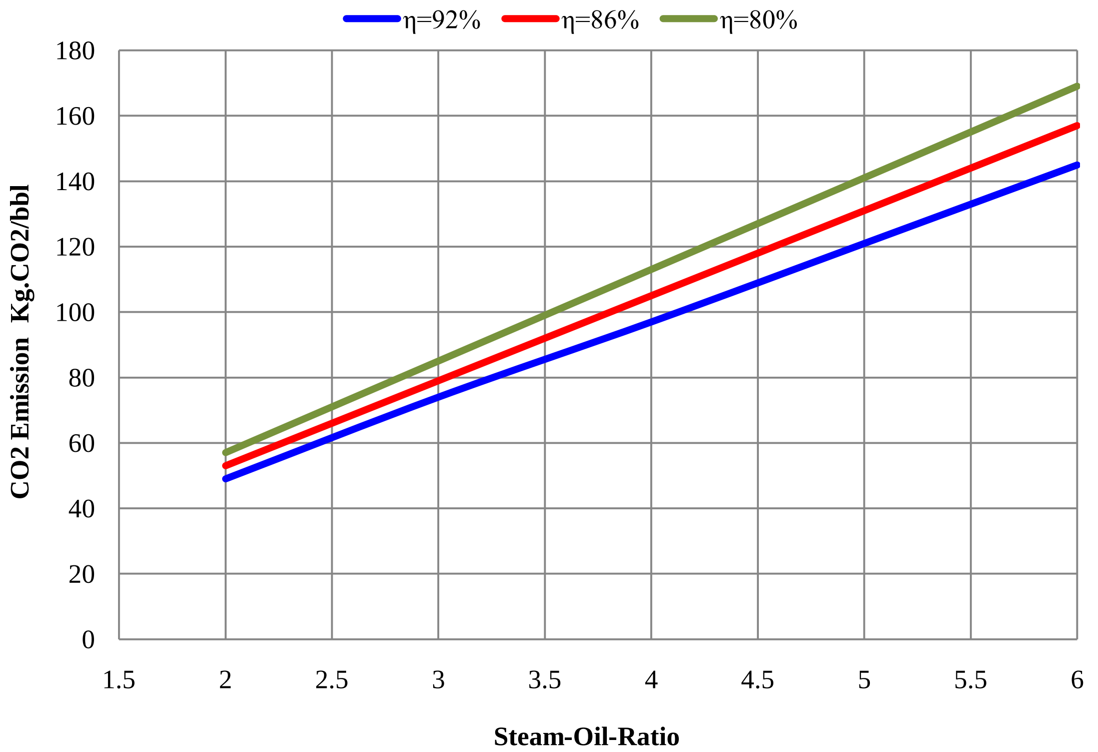


Figure 3-11: CO_2 emission as a function of SOR

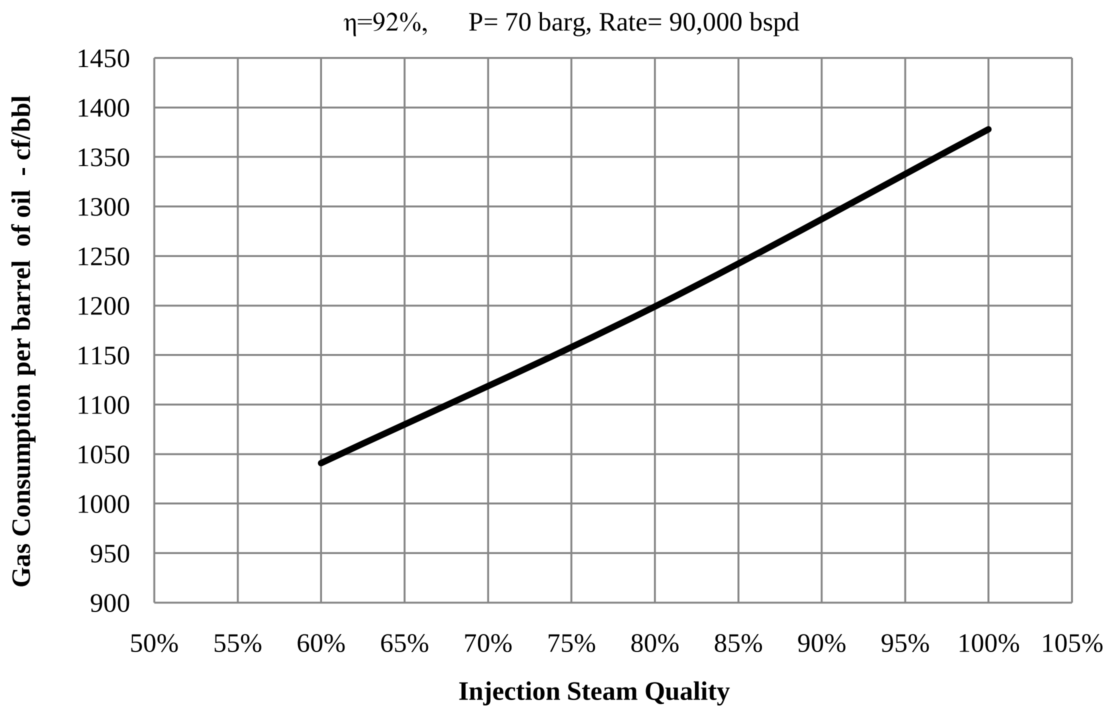


Figure 3-12: effect of the injected steam quality on fuel consumption

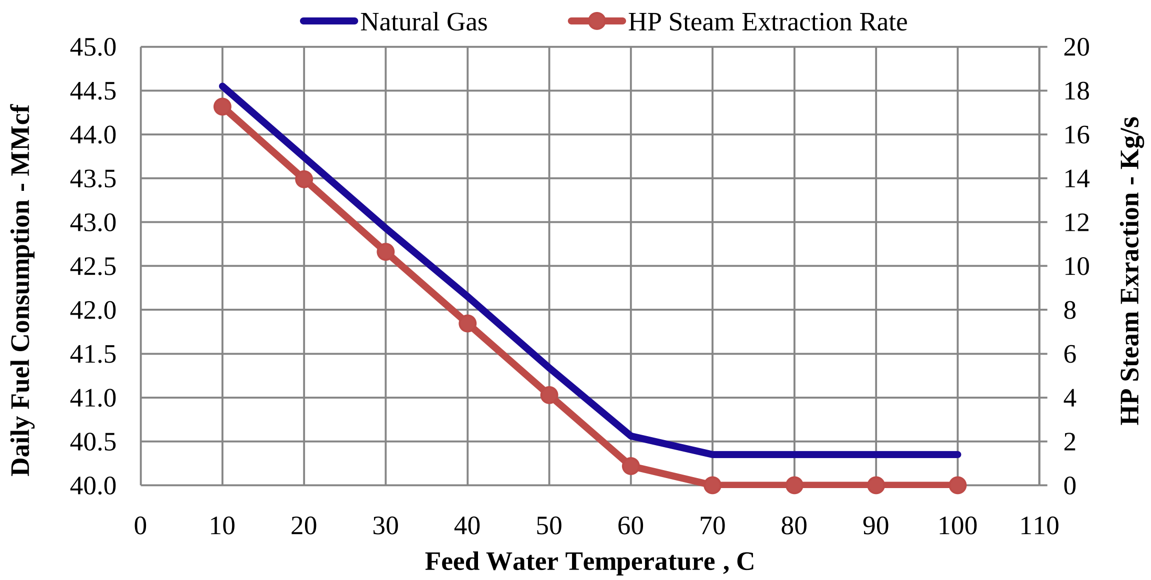


Figure 3-13: effect of feed water temperature on fuel consumption

3.6 Conclusion

The numbers of scenarios that can be simulated are large but only a few representative results have been presented in this chapter. Both fuel consumption and CO_2 emission vary widely under the considered SOR range. Natural gas consumptions varied from 920 to as high as 3200cf/bbl for a SOR in the range of 2 to 6. Under the same assumptions, CO_2 emission varied from 50 to 170 kg.CO_2/bbl. For references, the reported average CO_2 for West Texas Intermediate (WTI) and Saudi Medium is 5 and 25 kg.CO_2/bbl, respectively (IHS & CERA, 2010). The economic and environmental burdens of S-EOR projects are therefore clear.

It is also evident that the current practice of using the SOR as the economic indicator is flawed and could lead to sub-optimal decision-making. Quoting SOR without specifying the actual steam conditions makes it an incomplete indicator. For example, two projects with equal SOR but operating at different steam quality will have different fuel consumption and CO_2 emission, thus different operating costs.

The advantage of natural gas over crude oil as a fuel for steam generation has been illustrated. The use of natural gas results in lower fuel costs and CO_2 emission, making it the preferred fuel option in S-EOR projects.

4 Solar and Nuclear Energy for S-EOR Projects

4.1 Introduction

The above than average fuel consumption and CO_2 emissions from S-EOR projects, as demonstrated in Chapter Three, are raising legitimate concerns for unconventional oil developers about the future sustainability of such energy-intensive operations. Surging natural gas prices coupled with tightening environmental regulations, including emerging carbon limits, are encouraging both heavy oil developers and host governments to seek ways whereby they can reduce their dependence on natural gas.

There have been two broad opinions on how to tackle this issue. There are some who believe that by adopting energy efficiency measures such as cogeneration schemes can result in a considerable reduction in natural gas consumption. In addition to the potential saving in fuel consumption and GHG emissions, fossil-fuelled cogeneration technologies are technically proven and can therefore be readily integrated into oil field operations, thus avoiding the technical and financial risk typically associated with the use of immature technologies such as solar energy. For this reason, cogeneration is being increasing adopted by S-EOR developers to meet their steam demands. A detailed assessment of cogeneration for S-EOR projects is provided in Chapter Six of this thesis.

A more radical approach towards finding solution is calling for natural gas to be entirely displaced and that other cleaner and more sustainable energy sources to be used. Solar and nuclear energy have long being considered as potential sources for steam generation in heavy oil developments. One of the earliest studies on the use of nuclear energy for S-EOR projects was published in 1977 by Puitagunta, et al (1977) and for solar energy in 1982 by Peter, et al (1982).However, despite the number of studies that have indicated the economic and environmental attractiveness of these energy sources, they both have a very limited success in terms of field implementation. As of today, there is no nuclear plant operating in an oil field worldwide and the world’s first pilot solar plant was commissioned in February 2011 at Berry Petroleum Company's 21Z lease in McKittrick, California. U.S.

The limited success of these technologies for S-EOR application could only suggest that the problem is beyond that of pure economics. Against this background, the objective of this chapter is set to:

- Discuss from a subsurface point of view the viability of solar-generated steam for oil field injection.
- Carry out a detailed thermodynamic performance evaluation of a parabolic-trough solar field specifically configured to provide steam for S-EOR projects.
- Review published studies on nuclear to understand the main factors that have prevented this technology from being adopted by heavy oil developers.

4.2 Solar Energy

Solar, as a carbon-free and inexhaustible source of energy can undeniably reduce the world's reliance on volatile fossil fuel costs and cut GHG emissions. The solar technology, however, is still considered by many as technically immature and that there are still many technical and financial hurdles to overcome. Large scale solar installations are prohibitively expensive today and are most they often integrated with other forms of fossil-fuelled technologies in order to ensure an uninterrupted supply of energy.

Solar for EOR (solar-EOR) also have unique challenges. As discussed in Chapter Two, most S-EOR processes require continuous and interrupted supply of steam. However, solar-generated steam is influenced by daily and seasonal variations in solar energy which result in day-night as well as seasonal fluctuations in steam production. For stand-alone solar installations, this means that the steam injection process must be stopped during night when available solar energy is inadequate to produce steam at the required condition or quantity. In this case, the steam profile would be dictated by the availability of solar energy which may not coincide with what reservoir engineers need to optimize the oil recovery process. Therefore, the subsurface implications, if any, of injecting steam cyclically have to be understood and thoroughly evaluated before any other surface and economic factors are considered.

4.2.1 Subsurface Implications of Solar-Generated Steam

The ability of the oil reservoir to retain and utilize intermittent and diurnal heat supplied by solar systems is one of the most important considerations in solar EOR. This issue has been the subject of serious dispute and a number of studies have been published on this matter. These studies are discussed here.

Doscher et al (1982) conducted an experimental study to investigate the effect of diurnal steam injection on the performance of a steamflood process. Three set of experiments were conducted. In the reference experiment, steam rate was maintained at 28 barrels per hour throughout the day i.e. 670 barrels of steam per daily. In the second experiment, the hourly injection rate was doubled to 56 barrels but steam was injected for 12 hours only, resulting in the same daily cumulative steam as in the reference experiment. In the third experiment, the steam rate was injected 28 barrels per hour for 12 hours a day, resulting in a daily cumulative of 335 barrels i.e. half the amount in the reference case.

The study indicated that, although the same quantity of steam was injected in both the reference and second experiments, continuous steam injection resulted in higher oil rate and better SOR profile compared to diurnal injection particularly at early stages of injection. However, the differences between the two injection strategies started to diminish and the efficiency of the diurnal operation approached that of continuous operation as the recovery process matured and the steam zone became fully developed. The lower performance in the early stages of diurnal injection was believed to be caused by the cyclic collapsing of the steam zone, thus preventing it from being maintained at the vicinity of the production well. It was also observed that it took substantially more time (about 38%) to produce the same amount of oil in the diurnal injection case compared to the constant-rate injection.

The difference between constant-rate injection and diurnal injection magnified in the third experiment in which the total daily steam injection was half that of the reference experiment. In this case, the oil rate was slightly less than half that obtained in the constant-rate injection. In addition, the time required to deplete the reservoir increased by 64%; thus significantly increasing the project operating life. Because of the prolonged injection period, heat losses in the diurnal case also increased by 40%, which was reflected in a deteriorating SOR profile.

Hong (1988) studied the effect of temporarily shutting-in steam injection wells on the oil recovery of a steamflood project using a reservoir thermal simulator. Although Hong was not specifically examining the effect of solar-induced injector shut-in, some of his findings can be related to the solar case. He found that the severity of the effect primarily depends on whether the injector shut-in occurs before or after the onset of peak oil. If the injector shut-in occurs before the steam zone is fully developed, the onset of the peak oil production rate is delayed by more than the length of the shut-in period. However, the effect is somewhat lessened if injector shut-in occurs near or after the onset of peak oil rate. His analysis showed that steamflood performance is nearly reversible in nature, meaning that both the temperature and production performance could be brought back to near the pre-shut in states shortly after the resumption of steam injection. The general conclusion from Hong's study is that as long as the same amount of heat is injected, the sole effect of temporary shutting in the injector is to extend the operating life of the pattern. It is worth noting that Hong's numerical investigations were, to a very large extent, in good agreement with the prior experimental investigations carried out by Doscher et al (1982).

The effect of manipulating the steam injection rate in a SAGD process was investigated by Birrell et al (2005). They proposed that the steam injection rate can be manipulated to coincide with seasonal variations or temporary extremes in natural gas and crude oil prices. For example, steam injection can be temporarily suspended in the winter when natural gas prices used for steam generation are typically high. Production can then be resumed in the summer *at peak capacity* in order to compensate for the winter shut downs. As with the previous studies, Birrell and his team noted that the ability to shut-in steam injectors, without severely jeopardizing the performance of the oil recovery process, is mainly governed by the maturity of the injection process. They observed that for immature patterns, the reservoir temperature and pressure drop quickly upon the shut-in of steam injector, thus causing significant drop in the oil rate. The severity of the impact, however, started to ease as the steam chamber enlarges and the process becomes fully developed. They reasoned that the large steam chamber associated with mature patterns acts as buffer for short-term variations in steam injection.

Habsi et al. (2008) simulated the impact of steam injector shut-in on the oil recovery of a highly fractured reservoir in Oman. In this study, the field is developed using a unique thermal EOR technique known as Thermally-Assisted Gas-Oil Gravity Drainage (TAGOGD). The study indicated that failure to deliver steam would result in high oil production deferments. This was interpreted, apart from the cool off effect due to not providing heat, to be caused by a reduction in reservoir pressure following injector shut-in. The resultant pressure variation and movement of the oil rim causes some heated oil to go back into the matrix instead of flowing toward the production wells. It is worth noting that in this study it was assumed that the injection process is stopped for extended periods of time (1-3 months) potentially caused by failures in surface steam facilities or injection wells. It has to be said, however, that variations in solar energy is very unlikely to necessitate such prolonged injection shut-in.

A recent, and more detailed, study to evaluate the subsurface feasibility of solar EOR was jointly conducted by Shell Technology Oman and Petroleum Development Oman (PDO). The study main findings were later reported by Heel et al. (2010). Using both analytical modelling and thermal reservoir simulator, they investigated whether the cyclic nature of solar-steam will have a deleterious effect on oil recovery. They used two representative models for realistic reservoirs; the first is for a fractured reservoir and the second is for a non-fractured reservoir[13]. The study assumed that seasonal variations in the solar solar-generated steam can be represented by an oscillatory function and that steam is only available for 10 hours a day. It was also assumed that the same steam quantity is injected in the solar case as in the constant-injection case. Some representative results from the study are shown in Figures 4-1 and 4-2[14]. Figure 4-1 compares the simulated oil rates for the solar and constant-injection cases for the fractured reservoir.

[13]In the non-fractured model, the dominant recovery mechanism is steam-drive whereas in the fractured reservoir the recovery mechanism is TAGOGD

[14]Results are provided by Dr Ton Von Heel. Shell Technology Oman

It can be clearly seen that seasonal oscillations in the steam injection rate manifest themselves as oscillations in the oil rate. In this case, it was found that a $\pm$ 25% relative change in the steam injection rate is reflected in as a $\pm$ 7 relative change in the oil rate, see Figure 4-2.

The impacts of cyclic steaming were more pronounced in the non-fractured reservoir. A $\pm$ 25% relative change in the steam injection rate was initially reflected in as a $\pm$ 25 relative change in oil rate but later reduced down to $\pm$ 5. This change in amplitude was believed to be caused by the change of character of the recovery mechanisms from an initial steam-drive mode to a gravity-drainage mode.

Despite cyclic variations in oil rates, the *cumulative* oil recovery was found to be the same for both the solar case and constant-injection case. The study concluded that from a subsurface point of view solar generated steam is a viable alternative to constant-steam injection, provided that the same cumulative amount of steam is injected in both cases over the *same* period of time.

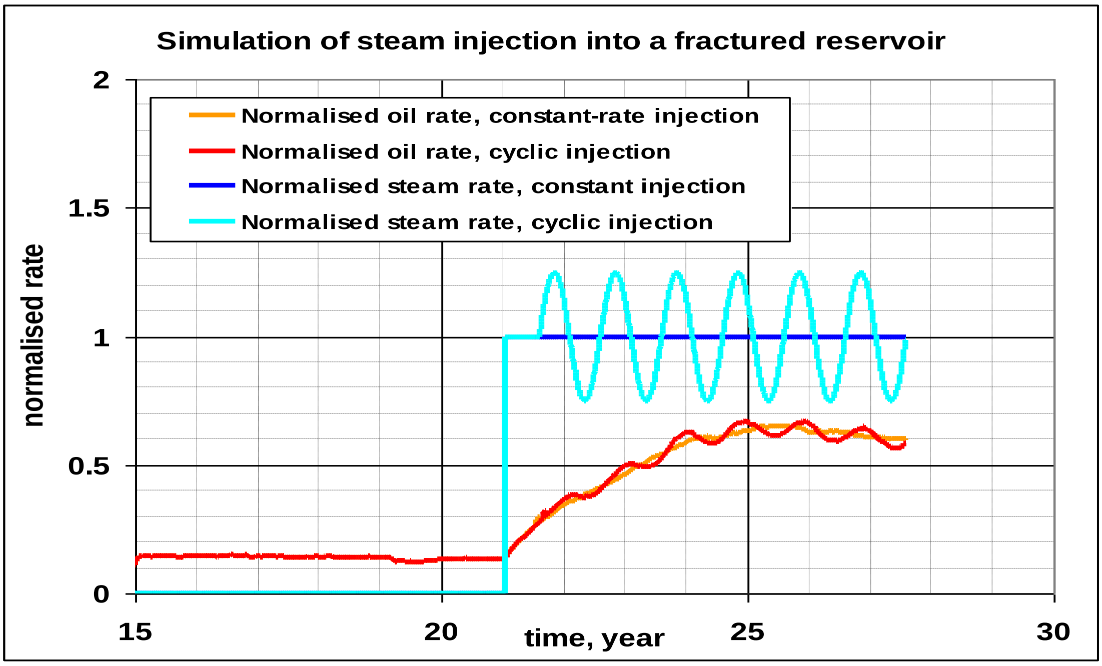


Figure 4-1: Oil rates for solar-steam and constant-rate injection profiles

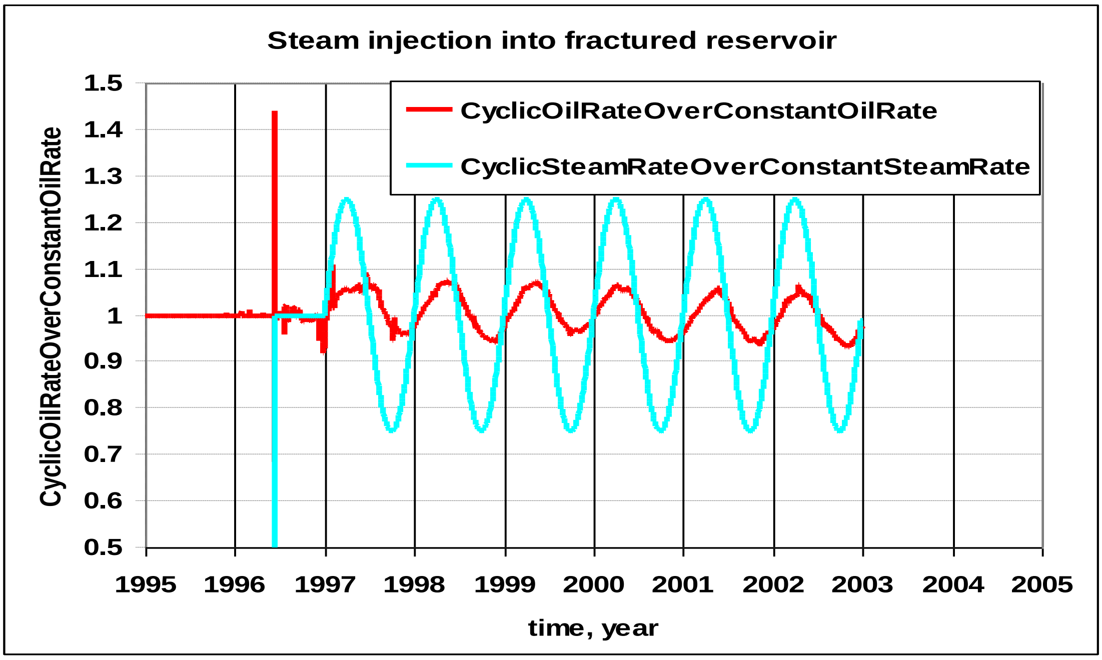


Figure 4-2: Normalized solar-steam rate and oil rates

4.2.2 Solar-EOR – Surface Evaluation

There are enough reasons presented in the previous discussion to suggest that from a subsurface point of view, solar-generated steam could be a viable alternative to constant-rate steam injection and that short-term variation in steam rate is not expected to cause major impact on the oil recovery process.

From a surface point of view solar energy for EOR has seldom been discussed in the literature and very limited studies have been published on this matter so far. Kenneth (1979) compared the economics of solar EOR project to a conventional fossil-fuelled S-EOR project. He assumed that the operation of the S-EOR project would be effected very little by the use of solar generated steam. The study concluded that solar-generated steam could become cost-competitive in the ‘near future’ with steam generated using oil-fired steam generators. It is evident, however, that the economic assumptions used in the study were unrealistic because the solar energy remains uncompetitive with conventional technologies up until today. In fact, a similar study published three years later and conducted by Peter, et al (1982) indicated that solar EOR was not economically attractive at that time and that government support through effective tax incentives is a prerequisite to make the solar technology cost-competitive.

A more recent study was conducted by Daniel et al (2009). They proposed the use of solar radiation to generate electricity15 and mid-temperature steam for 10,000 bopd oil sand project in the Athabasca region, Canada. They estimated that a total of 2.15 km^2 of reflector area would be needed to produce the required steam and electricity, costing over 531 $MM[16].Based on natural gas price of $0.6/kg, they estimated an annual fuel cost saving of 62$MM. The study also estimated that by displacing natural gas fired boilers, about 270,000 tonnes of CO_2 would be saved annually. At an assumed carbon tax of 4 cents per kg of CO_2, this would yield 10.8 $MM saving in carbon tax.

The studies discussed above have mainly focused on either the subsurface or the economics aspects of solar-EOR with little or no attention was given to the surface facilities. Instead, certain assumptions were made on these studies regarding the performance and operability of solar steam systems in order to simplify the subsurface analysis. Some of the studies assumed that the same cumulative amount of steam is injected over the same time-span for both the solar case and the constant-injection case. This would require steam to be is injected at peak rates during periods of high solar irradiance in order to compensate for steam unavailability during the night. On the other hand, some studies assumed that solar-generated steam will be injected at lower rates as compared to constant-injection case. In this case, longer time is required to accumulate the same amount of steam as in the constant-rate case, proportionally increasing the project's operating life. The economics of the projects in this case is penalized by higher present value discounting and delayed payoffs.

The promising findings reported by Heel, et al. (2010) coupled with a lack of studies on the performance of solar systems for S-EOR have encouraged the author to carry out a preliminary thermodynamic evaluation of solar steam plant specifically designed to supply for a S-EOR project. The main objective is to evaluate the practicality of the assumptions made in the subsurface studies regarding the solar-generated steam profiles and their effects on the design, sizing, and operation of solar steam plants.

[15] 7.77 MW of electricity is assumed to be generated through Solar Thermoelectric Generators at a conversion efficiency of 5%

[16]The cost of installing the Thermoelectric Generators was not included in their assessment. The reported costs is for steam generation equipments only

4.2.2.1 Parabolic-trough Solar Modelling

A full parabolic-trough collector solar steam plant is modelled in this study. The plant is modelled and simulated using Thermoflex thermal process simulator which contains a library of various standard components that can be used to model, in great level of details, solar systems.

Parabolic-trough solar system, Figure 4-3, is simply long parallel rows of curved glass mirrors that focus the sun's rays on an absorber pipe located along its focal line (Thorsten, et al., 2004). The concentrated solar energy heats a heat transfer fluid (HTF), typically synthetic oil, which is circulated through the pipes. The heated HTF is then passed through a heat exchanger where it transfers its heat to water, raising its temperature and hence converting it into steam. Produced steam can then be used for power generation or for process heat applications.

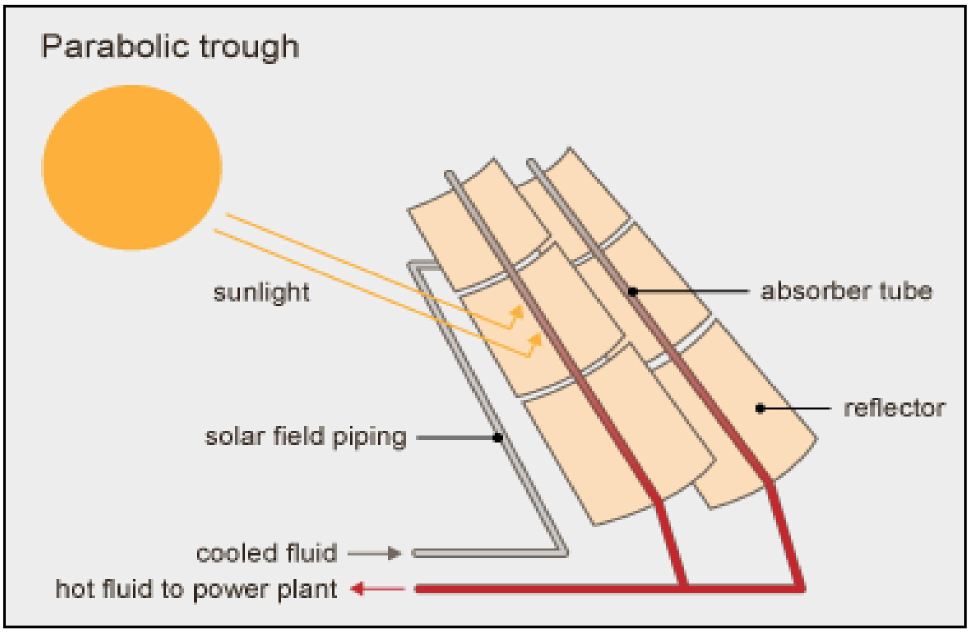


Figure 4-3: Solar parabolic-trough system[17]

[17] Source: http://www.wisions.net

4.2.2.2 Solar Irradiance Curve

Solar irradiance changes diurnally and seasonally and it is influenced by a number of environmental factors such as the presence of cloud and haze. Thermoflex uses an estimate of atmospheric transmissivity developed by Hottel (1976) to determine the fraction of solar flux reaching the field based on certain user inputs such as site latitude. However, this study uses actual metrological data for a site in Oman (Zurigat, et al., 2003). The report contains hourly solar irradiance data for a number of locations in Oman recorded over a number of years. An appropriate location was selected and a *representative day* was obtained by averaging the site hourly solar irradiance data throughout the year. The need for this approach is explained later. The representative day solar irradiance is shown in Figure 4-4.

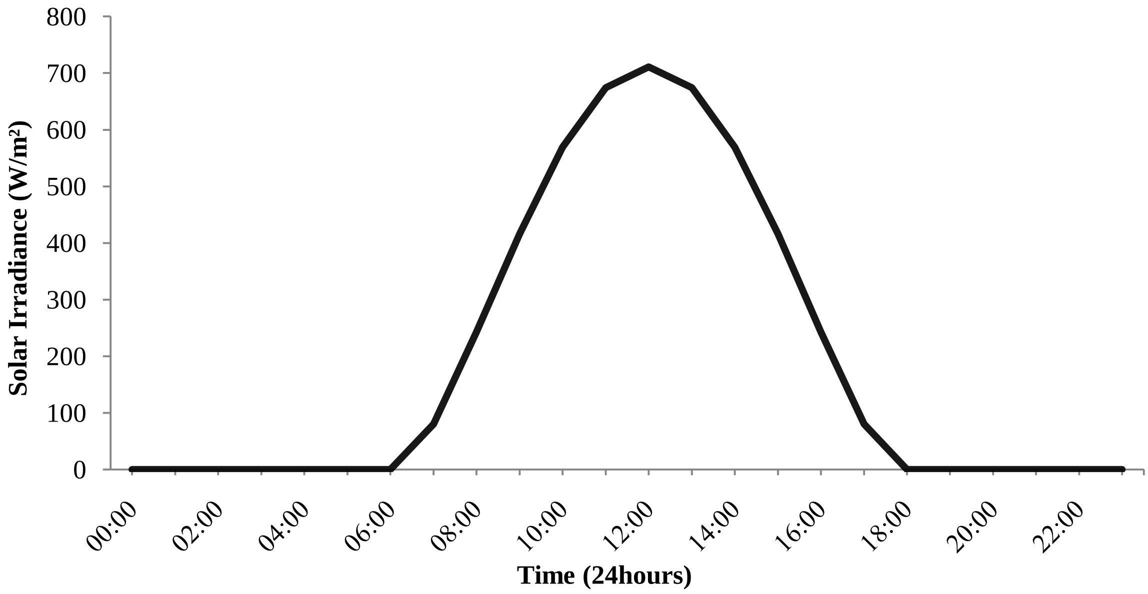


Figure 4-4: Solar irradiance curve of the representative day

4.2.2.3 Solar Plant Description

For the ease of comparison, Field-A described in section 3.2 of Chapter Three is considered. The steam plant is identical to the one described in section 3.2 but with the fossil-fuelled boilers being replaced with parabolic-trough collectors. Figure 4-6 is a schematic of the solar facility.

Table 4-1: Field-A steam requirements

Field Size (b/d)	Pressure (barg)	Temperature (°C)	Quality (%)	Steam Rate, CWE (bspd)	SOR -
30,000	70	287	100	90,000	3

4.2.2.4 Solar Plant Control

A significant challenge that must be addressed in the design and operation of a parabolic-trough solar field is the control of the HTF outlet temperature. In this study, Therminol VP-1 synthetic heat transfer fluid is used. This HTF has maximum and minimum operating temperatures of 398.9 °C and 12.8 °C, respectively.

In general, temperature-control in parabolic-trough solar plants is constrained by the maximum temperature the HTF can tolerate as well as the requirements of the process using the thermal energy (Schindwolf, 1980). Various thermal applications such as power generation and process heat have varying temperature-control requirements and temperature-control systems. Power generation, for example, demands stringent temperature-control of the produced steam before it can be admitted to steam turbines. This study, however, is concerned with less stringent temperature-control requirements. Saturated steam for oil field injection is pressure-limited rather than temperature-limited. As long as the achievable HTF exit temperature is adequate to generate the field require steam pressure, the HTF outlet temperature is of a secondary importance. In keeping with this conclusion, constraints on HTF temperature control are eased under certain operating conditions in this study. This allows the steam generation process, and thus field injection, to start earlier than what would have been possible if the exit temperature is maintained at its maximum limit throughout the entire operating envelope.

Control of the HTF outlet temperature is typically achieved by manipulating the volume flow of the HTF through the collector loop (Zunft, 1995). Continuous load bypass can also be used but the low efficiency and dynamical disadvantages of this technique restrict its use to auxiliary manipulation only. Temperature-control of parabolic-troughs systems remains largely manual today (Thorsten, et al., 2004). A number of studies have been carried out in order to develop reliable control algorithms that would enable automated control of solar plants (Schindwolf, 1980) (Zunft, 1995)(Thorsten, et al., 2004). A major challenge lies in achieving a well-damped and fast closed loop response with simple controllers driven by transportation delays of the HTF in the collector loops. Further complexity arises due to the existence nonlinearities in the heat transfer in the absorber and the HTF (Zunft, 1995).

In this study, Thermoflex control capabilities is used to control outlet temperature of the HTF by adjusting the HTF flow rate being re-circulated through the solar collectors. The HTF maximum outlet temperature is set at 390 °C, nine degrees lower than the maximum temperature Therminol VP-1 HTF can safely attain. In real life operations this temperature margin is required to allow for temperature increase above the set-point during transient operations without overheating the heat transfer fluid (Schindwolf, 1980).

The simulated operating envelope of the HTF is shown in Figure 4-5. It is clear that the HTF temperature set-point could only be maintained at 390 °Cfor about 7 hours during the day where the available solar energy is relatively high. In order to generate more steam during periods of low solar irradiance, the temperature set-point was gradually reduced while still maintaining the steam pressure that the required 70 barg.

It can also be observed that the HTF undergoes substantial flow rate changes to respond to changes in solar irradiances. It is worth mentioning that neither the maximum nor the minimum HTF flow rates are constrained in this study. In real life operations, however, it may be necessary to limit HTF flow rate for economical or operational purposes.

Similar observations were made by Jones, et al (2001). They modelled the SEGS VI parabolic trough plant in California’s Mojave Desert and compared their model predictions with actual field measurements. For a typical sunny summer day, the study indicates that the measured HTF exit temperature did not reach the set-point of 380 °C until about 9:00 am when sufficient irradiance was available.

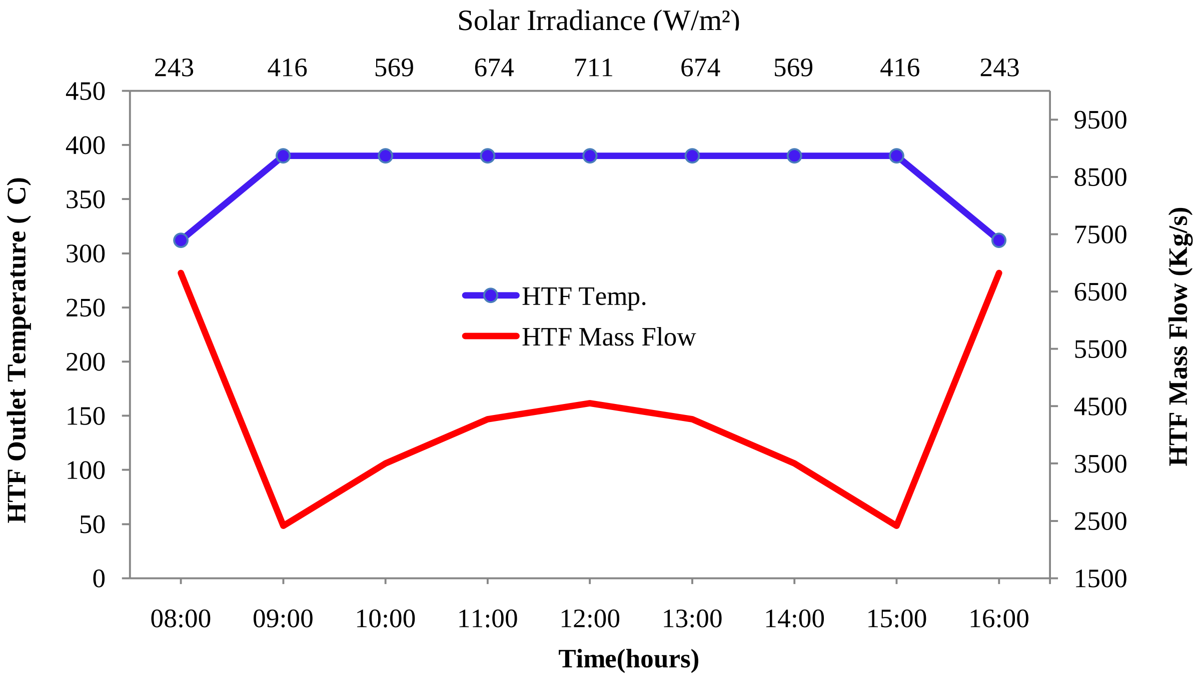


Figure 4-5: The HTF operating envelop

4.2.2.5 Solar Plant Sizing

In order to evaluate the assumptions made in the subsurface studies discussed earlier, two operating strategies are considered:

- Operating Strategy-1: the solar plant is designed to provide a daily cumulative of 90,000 bspd, the same cumulative as in the constant-rate case.
- Operating Strategy-2: the size of the solar plant is fixed at 1.5 km^2 and the performance of the plant is simulated under the representative day assumption to determine the amount of steam that can be generated.

Solar thermal plants are typically rated at a specified solar irradiance value and plant size. However, due the variable nature of solar energy, the thermal output form a solar plant rarely reaches that of its rated capacity because the amount of thermal energy that can be generated will depends on a number of factors which are beyond of the operator's control such as the prevailing meteorological conditions. It can therefore be seen that designing a stand-alone solar system to produce a specified daily cumulative output is an exemption rather than the norm. However, with respect to thermodynamic modelling, a solar steam plant can be designed to produce a specified amount of steam based on a given solar irradiance profile. Then the targeted steam rate can only be maintained as long as the site solar irradiance profile and other operating parameters remain unchanged.

Sizing a solar plant to provide a specified daily cumulative requires a long iterative process. A flow chart of the iterative process adopted in this study is shown in Figure 4-7. The iteration process is repeated until the 90,000 bspd target is obtained for the representative day. Some of the key inputs used in simulating Operating Strategy-1 are listed in Table 4-2.

Operating strategy-2 is less complex to simulate simply because it is a more realistic representation of real life and fits within Thermoflex simulation's hierarchy. In this case, the aperture area of the field is limited to 1.5 km^2 and the solar plant performance is simulated for the representative day. Some of the key inputs used in simulating Operating Strategy-2 are listed in Table 4-3.

Table 4-2: Main input parameters for strategy-1 simulations

Input Parameter	Value	Unit
Collectors Efficiency	75	%
Aperture normal direct irradiance	711.6	W/m^2
Heat Transfer Fluid	THERMINOL VP-1	
HTF Mass Flow at Solar Field	4550	kg/s
Solar Filed Inlet Temperature	235	°C
Solar Field Outlet Temperature	390	°C

Table 4-3: Main input parameters for strategy-2 simulations

Input Parameter	Value	Unit
Collectors Efficiency	75	%
Aperture normal direct irradiance	711.6	W/m^2
Heat Transfer Fluid	THERMINOL VP-1	
HTF Mass Flow at Solar Field	1724	kg/s
Solar Filed Inlet Temperature	231	°C
Solar Field Outlet Temperature	390	°C
Reflector Aperture area	1.5	km^2

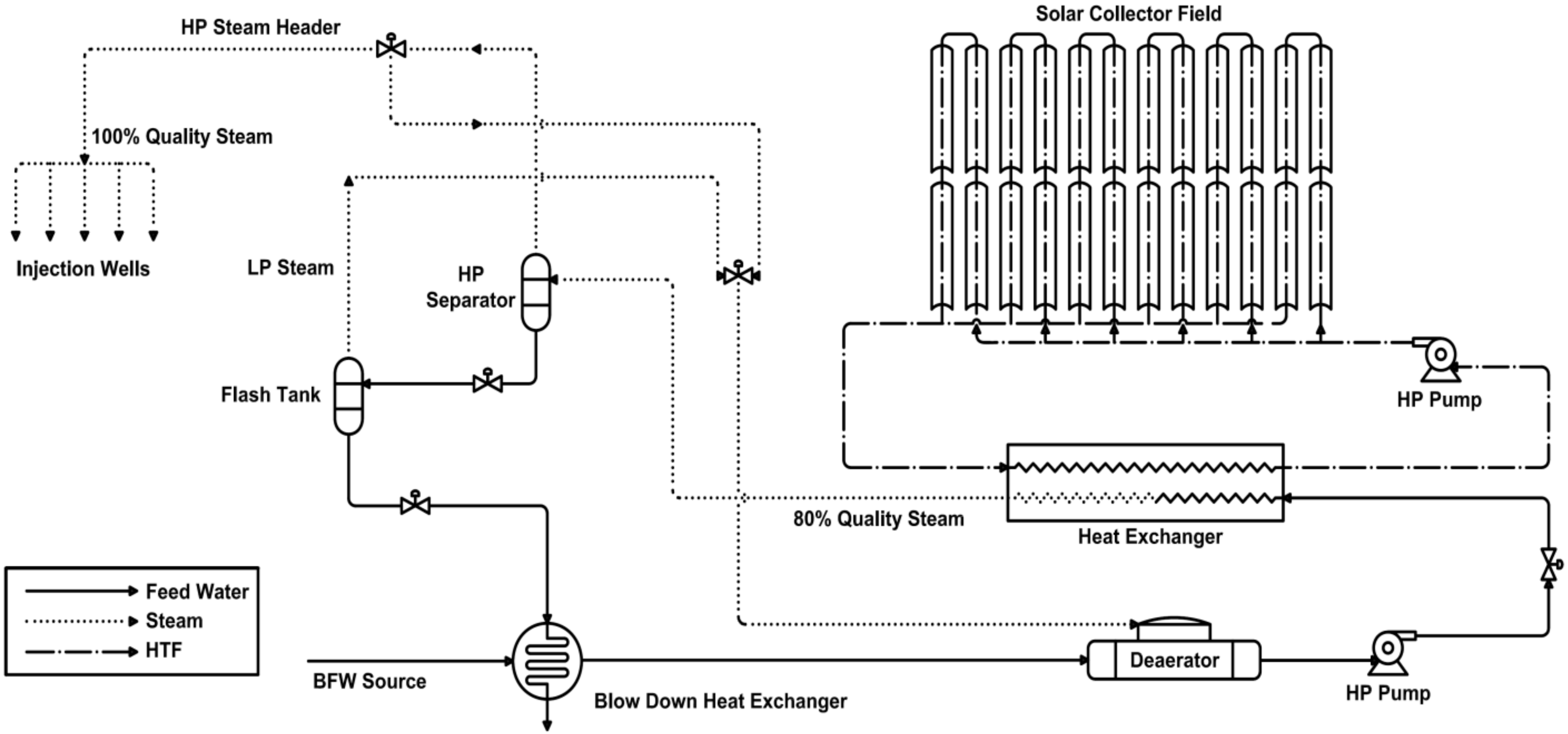


Figure 4-6: Schematic of the simulated parabolic-through solar field

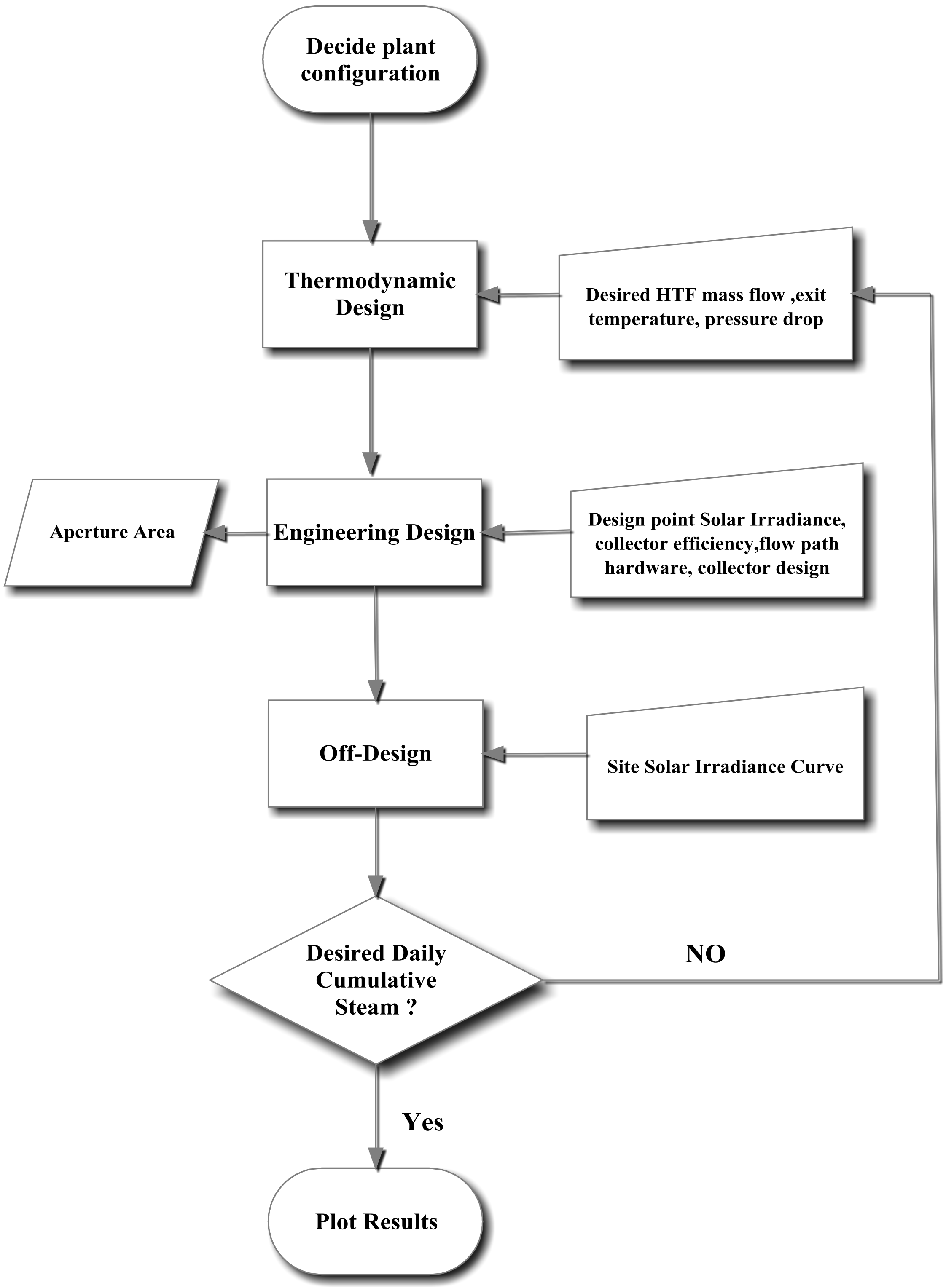


Figure 4-7: Flow chart of solar field sizing procedure for operating strategy-1

4.2.2.6 Results and Discussion

The objective of Operating Strategy-1 is to produce daily cumulative steam of 90,000 barrels i.e. equivalent to the constant-injection case. The steam production rate from the solar plant as a function the site solar irradiance is shown in Figure 4-8. Figure 4-8 shows that diurnal variations in solar irradiance are reflected in diurnal variations in steam production rate. It can also be seen that the steam production can only be maintained for less than 9 hours a day (from 8:00 to 16:00)[18]. This means that field injection will have to be suspended for over 15 hours a day.

Operating Strategy-1, although simplifies subsurface evaluations, imposes a number of surface and subsurface challenges. Steam has to be produced at peak rates during the day when the solar energy is at its peak in order to compensate for steam unavailability during the night. To meet the 90,000 bspd target, Figure 4-8 indicates that steam will have to be produced at a peak rate of 14,650 barrel per hour (bbl/hr) i.e. a rate which is 3.7 times greater than that required for constant-rate injection (4,000 bbl/hr). Accordingly, the solar plant has to be sized to produce the expected peak rate. As indicated in Figure 4-8, a 3.5 km^2 of collector area is required to produce the 90,000 bspd target. This is a significantly large solar installation by today's standards, and as a result the economics of the project would be penalized by higher capital investment. In addition, the large variation in steam production rate associated with stand-alone solar plant requires steam equipments to be designed with large turn-down capabilities, and thus adding further complexity and cost to the plant operation.

The cyclic nature of solar-generated steam poses some mechanical issues as well. Because the injection process is stopped at night, the temperature of the injector will subsequently fall, causing the well's tubing to contract. Cyclic cooling and heating of injectors casing and tubing lead to sever thermal stresses. If these stresses are allowed to exceed the design stress of these components, tubing failure may result (Earlougher, 1969) (Partha, et al,1992).

[18] It is worth to note that the steam generation process itself lasts longer (from 6:00 to 18:00). However, steam generated during these early and late periods is entirely consumed within the steam plant to preheat the feedwater, and therefore it is not available for field injection.

Peak steam rates will also require higher reservoir steam-injectivity. Steam injectivity simply defines the maximum steam rate that can be tolerated by the reservoir. Injectivity is unique to each reservoir and depends on a number of factors such injection pressure, reservoir pressure, rock properties (permeability and porosity), and fluid properties (oil viscosity) (Satriana, et al., 1998). The number of steam injectors required is primarily influenced by the reservoir injectivity. To evaluate the impact of solar-generated steam on steam injector requirement, an injectivity limit of 2516 barrel of steam per day per steam injector is assumed in this study[19]. The number of injection wells required in each operating scenario is shown in Figure 4-8. As indicated in Figure 4-8, more than 100 additional steam injectors will be required to handle the peak steam associated with the solar system. To make matter worse, injection and production wells in S-EOR operations should be designed to handle problems associated with elevated temperatures, thus requiring more expensive materials and well completions.

Another concern of using more injection wells arises due to the fact that the ultimate oil recovery from the additional wells would depend on where these wells are located in reference to what was initially in plan. For optimum operations, reservoir engineers have to maintain a certain well-spacing within a limited radius. In this case, additional wells may have to be drilled away from the crestal part of the reservoir. Steam injectivity tends to deteriorate away from the crestal part of the field where the effective reservoir thickness is typically less and pressure is higher, which may result in higher heat losses and lower ultimate recoveries.

However, it is worth noting that the issue of reservoir injectivity in solar-EOR operations is still a matter for debate. There are some who believe that by continuously producing the reservoir fluids even while the injection process is suspended, the reservoir pressure will drop substantially over night, and as a result improves the injectivity during day time. Under this assumption, the number of steam injectors shown in Figure 4-8 should be considered as the upper limit, or the worst-case scenario, in terms of injection well requirements.

[19] Although this value is obtained from an actual steamflood project, it should not be used as guide since each field will have its own operating characteristics.

Some of the issues associated with Operating Strategy-1 such as the large solar area required and the peak steam rates can be alleviated by allowing steam to be injected at lower rates. This operating strategy is simulated by limiting the solar field area to a more practical value of 1.5 km^2. Figure 4-9 compares the steam profiles of both operating strategies. The advantage of Operating Strategy-2 is very clear. The peak steam rate was reduced by 57% from 14,650 to 6340 bbl/hr, and as a result fewer steam injectors would be required. Furthermore, less capital investment would be needed due to the smaller solar plant and lower peak rates.

The main drawback of this operating strategy, however, is that longer time will be needed to deplete the reservoir due to the lower injection rates. In this case, the economics of the projects would be penalized by higher present value discounting due to delayed project cash flows. Figure 4-10compares the time required to accumulate 32 million barrels of steam for both operating strategies. It can be seen that Operating at strategy-2 requires 130% more time to produce the same amount of steam as in operating strategy-1. Another concern of injecting at lower rates is that it results in a large proportion of the injected heat being lost because of the prolonged injection period, as investigated by Doscher, et al., (1982) and Butler (1991).

Effect of Clouds and Haze

Clouds and haze are examples of daily factors that could significantly impact the performance of solar steam plants. The effect of cloud in the performance of the solar plant is simulated by assuming scattered clouds between 11:00 to 12:00, and low could between 12:00 to 13:00. Figure 4-11 indicated that the daily steam production drops by 90% from 90,000 barrels to 82,000 due to the short presence of clouds. Haze is another environmental factor that is also known to have profound impacts on the performance of solar plants. In this study, haze is simulated by reducing visibility down 5 km. Figure 4-12indicatesthat the steam production capability of the solar plant drops by 40% from 90,000 to 34,700 bspd. It can also be seen that steam is only produced for about five hours a day i.e. four hours less than the clear-day scenario.

Reservoir Heat Management Challenge

For optimum and cost-effective operation of S-EOR fields, reservoirs engineers need to know how much heat has been injected into the reservoir so that they can evaluate the performance of the field and to plant for future injection profiles. This is typically achieved by continuously or periodically monitoring certain parameters such as steam injection rate, steam quality, and pressure and temperature traverse. Changes in injected steam rate and steam quality are the most common operational adjustments made in S-EOR operations. In fossil-fuelled steam facilities adjustments to steam rate and/or steam quality can be easily accomplished by manipulating fuel flow to the steam boilers or supplementary firing in the case of cogeneration. This task, however, is greatly complicated in stand-alone solar operations because steam output from the solar plant is affected by the weather conditions and it changes continuously and in most cases unpredictably. In this case, the steam injection profile is primarily driven by the output characteristics of the solar steam plant rather than being optimized from subsurface viewpoint.

Representative Day Assumption

To check the validly of the representative day assumption considered in this study, 365 simulations were carried out representing each day of the year. Figure 4-13 shows the monthly cumulative of these simulations. For the simulated cases, the monthly cumulative was the lowest in January (33% less than the constant-rate case) and highest in September (25% higher the constant-rate case).

Surprisingly, the difference in terms of annual cumulative steam between representative-day and the 365-simulations is found to be negligible at about 1%, See Figure 4-14. The value predicted for the representative day and the 365-simualtions is 32.87 and 32.42 million barrels, respectively. Therefore, the use of a representative day in the design or performance evaluation of solar steam plants could provide a time-effective and accurate approach.

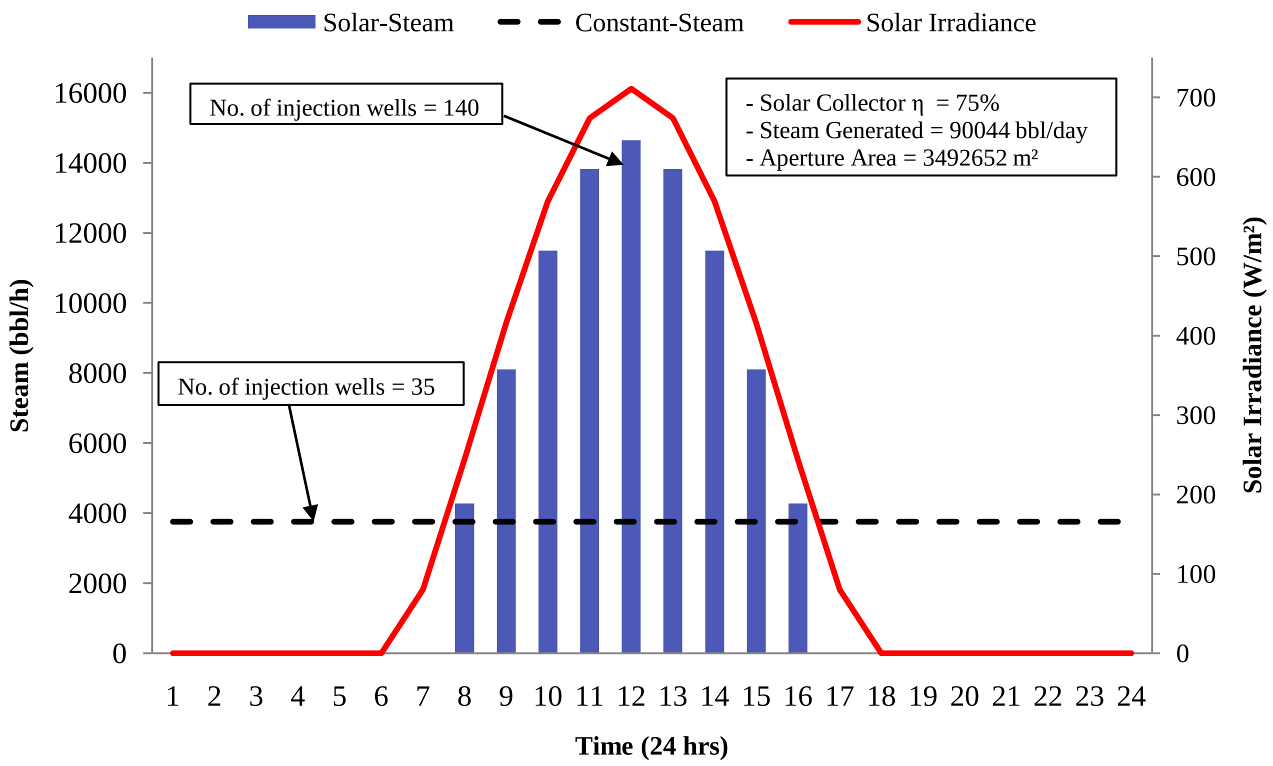


Figure 4-8: Solar field performance characteristics

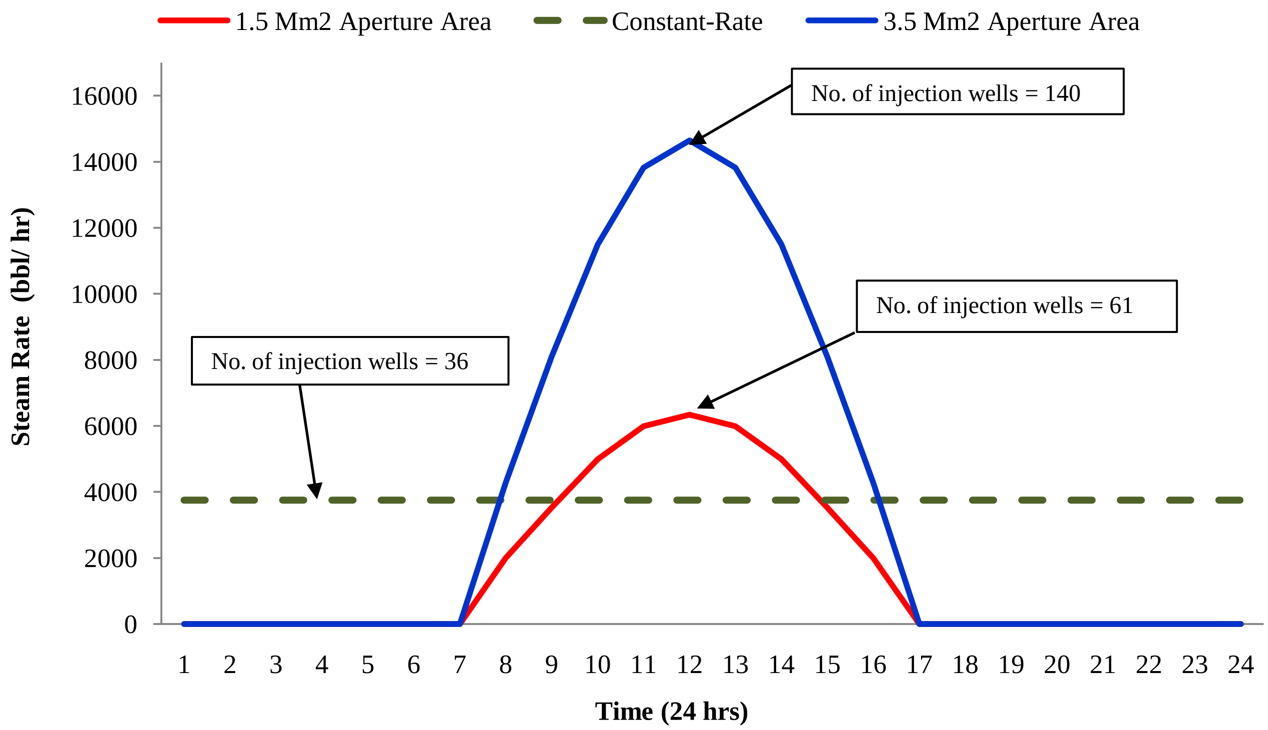


Figure 4-9: Performance comparison of operating strategies 1 & 2

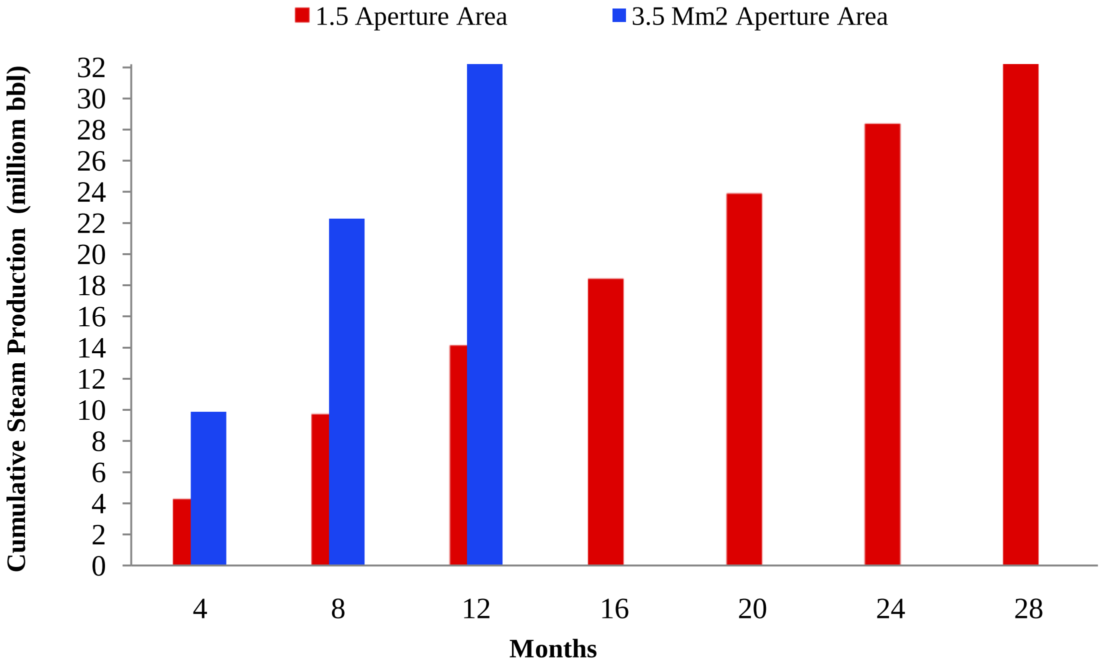


Figure 4-10: Time required to accumulate equivalent steam volume for strategies 1&2

- Solar Collector η = 75%
- Visibility Less Then 5 Km
- Steam Generated = 34709 bbl/day
- Aperture Area = 3492652 m²

Figure 4-11: Effect of haze on the performance of the solar steam plant

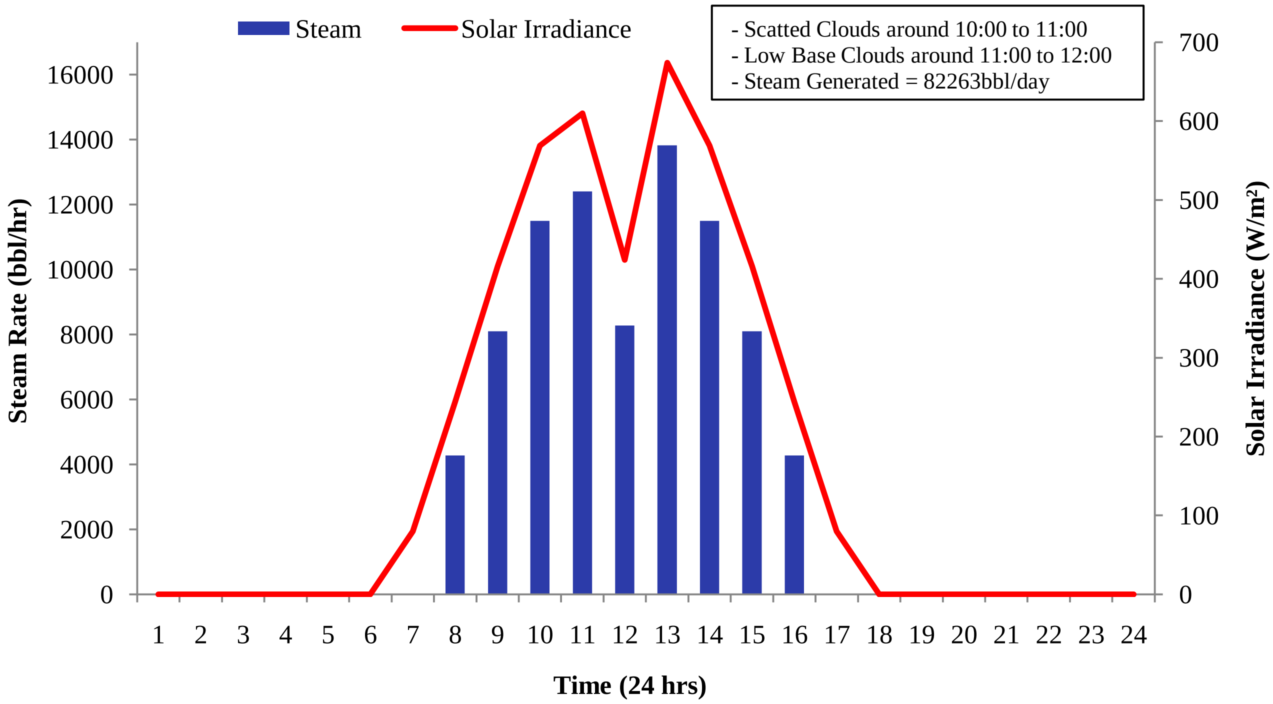


Figure 4-12: Effect of haze on the performance of the solar steam plant

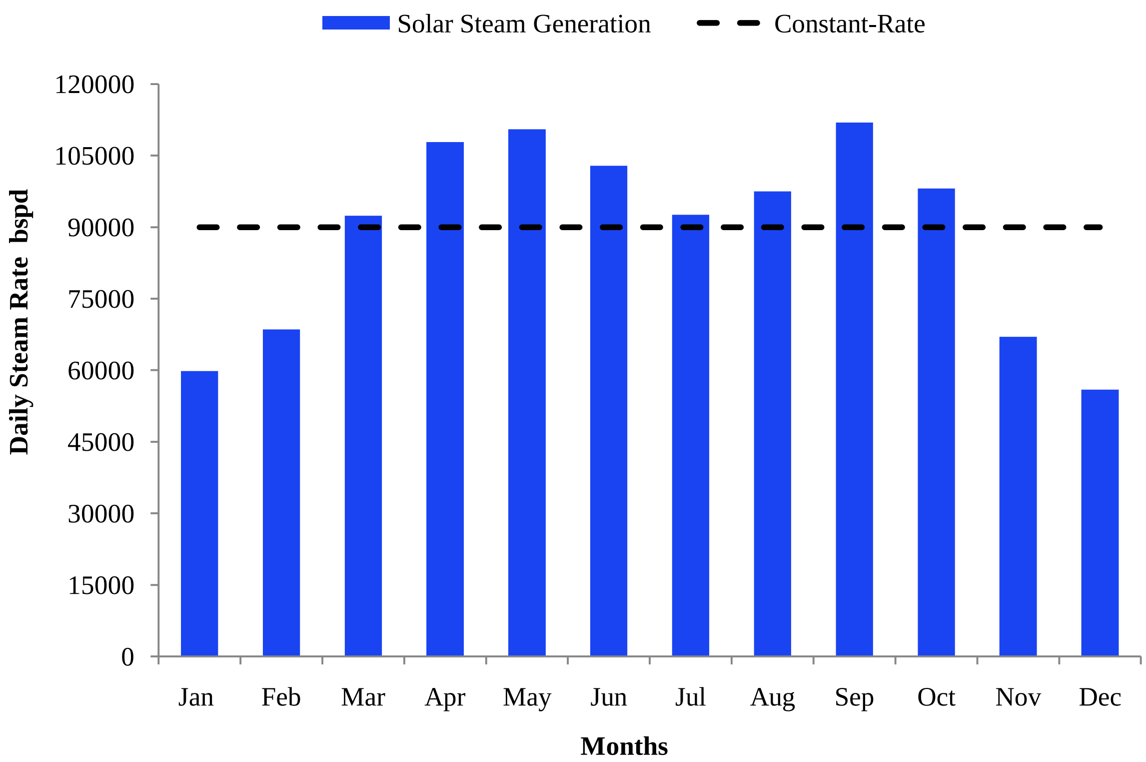


Figure 4-13: Average daily steam rate for different months throughout the year

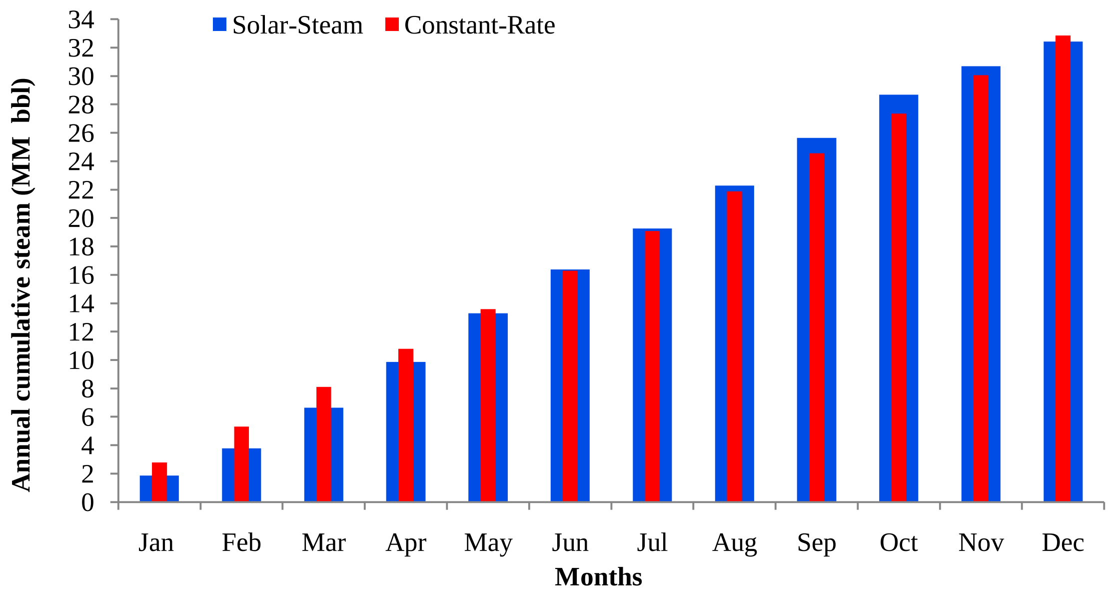


Figure 4-14: Annual cumulative steam rate for constant-rate and solar-rate

4.2.3 Conclusions

There are enough evidences to believe that from a subsurface view point solar-generated steam could be a viable alternative to constant-rate steam. However, there remain differences of opinion suggesting that an industry consensus on the matter is yet to be reached. Based on the reviewed literature, it can be seen that more research is needed to evaluate the impact of intermittent steam injection on the oil recovery process during the early phase of the steam injection program. The recovery process during this period is typically pressure-limited because the steam zone is not fully developed and has not moved vary far from the point of injection. Intermittent steam injection may cause the steam zone to collapse cyclically, which could have deleterious effect on reservoir response.

The effect of solar- steam on reservoir injectivity requires further explanation. If the reservoir injectivity turns to be a limiting factor then the response of the field would be delayed. In this case, the economics of the projects would be penalized by higher present value discounting due to delayed project cash flows.

Surface-wise, there are still a number of challenges facing the integration of solar technology into S-EOR operations. These include large solar installation, large variations in steam output due to various environmental factors, and fatigue effects of injector wells due to thermal cycling.

4.3 Nuclear Energy for S-EOR

4.3.1 Introduction

Nuclear energy is typically used for power generation. However, a new breed of small-scale and inherently safe reactors could pave the way for this technology to penetrate into other energy-intensive processes such as those found in the petrochemical and heavy oil industries.

The potential of nuclear energy as a heat source in S-EOR projects has long been recognised by the International Atomic Energy Agency (IAEA) (Hernan, 1989) (Barnet, et al., 1991) (IAEA , 2007). Nuclear energy has the potential to supply low-cost and low-emissions steam to support heavy oil operations (Finan, et al., 2010). Even when processes such as fuel enrichment, manufacturing, and construction are accounted for, nuclear energy results in little GHG emissions. A recent study conducted by Alsema et al. (2006) indicated that life-cycle emissions from nuclear (6 gm CO_2eq/kWh) are lower than solar using photovoltaic (25 gm CO_2eq/kWh) and wind (11 gm CO_2eq/kWh). Furthermore, the use of nuclear energy can free-up fossil fuels for other unique applications such power generation, petrochemicals, and transportation.

A number of studies have been conducted over the past four decades by major oil companies and government agencies to explore the potential of using nuclear energy in S-EOR operations (Puitagunta, et al., 1977)(Rao, et al., 1981) (Djokolelono, et al., 1988) (Hernan, 1992)(Finan, et al., 2010) . Many of these studies have indicated that, under certain favourable market conditions, the nuclear option is economically competitive with fossil fuel technologies. Despite this, there is no nuclear steam plant operating in an oil field today, which can only suggest that the problem is beyond pure economics.

Commercial nuclear reactors are designed and optimized for power generation. Therefore, one of the most fundamental issues when considering nuclear for oil field applications is whether the outlet steam conditions of the proposed nuclear technology are suitable for field injection.

The fact that the primary process in the core of the nuclear reactor is the conversion of nuclear energy into heat means that in principle all nuclear reactors could be utilized for process heat applications. In practice, however, two criteria are decisive: the outlet temperature of the reactor's coolant and the pressure of the produced steam (Barnet, et al., 1991). The outlet temperature of the reactor's primary loop (number 7 in Figure 4-15) limits the maximum temperature and pressure at which steam can be generated in the secondary loop (number 12 in Figure 4-15).

The objective of this section is to review published studies on nuclear energy for S-EOR in an effort to pinpoint the main technical factors that have prevented this technology from being adopted by heavy oil developers.

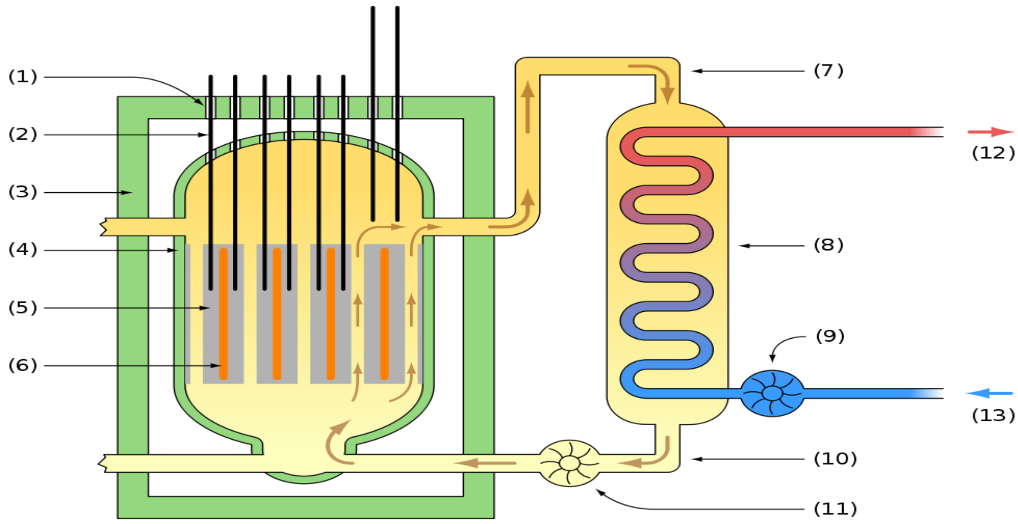


Figure 4-15: Simplified schematic of a nuclear reactor[20]

4.3.2 Nuclear for S-EOR

The output temperature from the core of various types of commercial nuclear reactors is listed in Table 4-4(IET, 2005)(Kenneth, 2009). Boiling Water Reactors (BWR) use demineralised water (light water) as a coolant and neutron moderator. The BWR design does not have a separate steam loop. Instead, heat produced by nuclear fission in the reactor core causes the cooling water to evaporate to steam which is then directly fed into steam turbines, see Figure 4-16. The cooling water is typically maintained at about

[20] source: http://thatscienceguy.wordpress.com

69 barg so that it boils at about 286 °C (IAEA, 2005). If the BWR is to be used for process heat applications, steam from the core of the reactor can be sent directly to the heat sink. However, for additional safety against escape of fission products from the reactor core, a heat exchanger could be installed between the primary steam loop and the process heat sink (MacMillan, et al., 1973).

Table 4-4: Outlet temperature from the core of various nuclear reactors

Reactor Type	Coolant Outlet Temperature (°C)
Boiling Water Reactor, BWR	286
Enhanced CANDU 6 (Heavy Water)	305
Pressurized Water Reactor, PWR	316
Advanced Gas Cooled Reactor, AGR	650
Pebble Bed Modular Reactor, PBMR	750
High-Temperature Gas-Cooled, HTGR	950

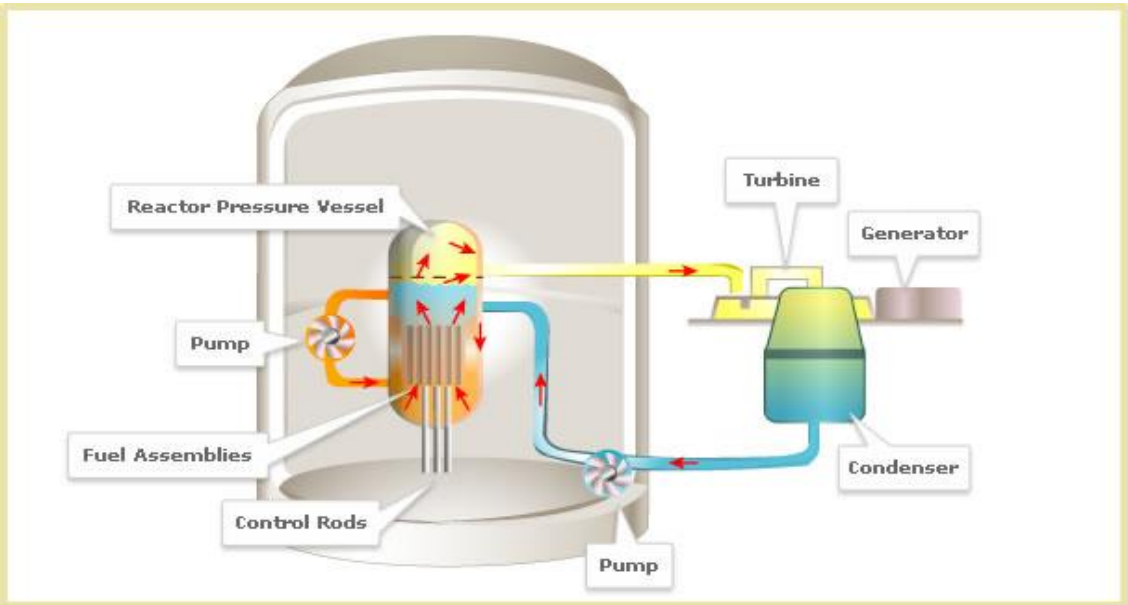


Figure 4-16: A simplified schematic of boiling water reactor

The majority of commercial reactors, however, incorporate two, or more, loops in their original design. In this case, the primary coolant loop transfers heat into a secondary heat transfer loop where steam is generated at the required conditions, see Figure 4-15. The additional of a secondary heat transfer loop, although improves safety aspects, imposes the penalty of increased differential temperature between the primary and secondary loops.

Pressurized Water Reactor design (PWR), the worlds' most widely used commercial reactor, is an example of two-loop nuclear reactors. PWR uses water as both coolant and moderator. In contrast to the BWR, high pressure in the primary coolant loop prevents the water from boiling within the reactor. The pressure in the primary coolant loop is typically twice that of BWR (150–160 bar). However, the temperature difference induced by the heat exchange process means lower outlet steam temperature can be obtained from this type of reactor. Table 4-5 shows the inlet/outlet steam conditions of the AP600 PWR (IAEA, 2005). It can be seen that the outlet temperature is reduced from 315.6 C° at the outlet of the primary loop to 273 C° at the outlet of steam generator.

Steam conditions from water-cooled reactors are generally considered too low for most S-EOR operations, particularly for deep reservoir injection (Barnet, et al., 1991) (Hernan, 1992). On the other hand, modifying these reactors to suits oil field application is a prohibitively expensive task and would necessitate a full system analysis and redesign to modify the reactor operation. Regulatory review to approve such modifications would also be required (Finan, et al., 2010).

Table 4-5: Inlet/outlet steam conditions of the AP600 PWR

	Inlet Steam Condition	Outlet Steam Conditions
Reactor Coolant System	280 °C / 154[21]barg	315.6 °C/ -
Steam Supply System	285 °C /71.1 barg	273 °C /56.4 barg

[21]Reactor Operating Pressure

A better alternative for field applications is temperature gas-cooled reactors (TGR) such as the Pebble Bed Modular Reactor (PBMR) and the Advanced Gas-Cooled Reactor (AGR). These types of reactors are capable of producing high pressure and temperature steam needed for oil field injection (Hernan, 1989). The maximum temperature of the primary coolant of various commercial gas-cooled reactors is shown in Table 4-4. The high temperature from the core of these reactors allows the production of high pressure steam that could potentially be used for deep reservoir injection.

One of the earliest studies, sponsored by General Atomic (GA), on the use of gas-cooled reactors in S-EOR operations was conducted by Rao and McMain (1981). Rao and McMain investigated the feasibility of using two 600 (MW_t) modular helium reactors (MHR) for the recovery of different types of unconventional oil. For the tar sands case, for example, the plant was configured to provide steam and electricity required by the oil extraction and upgrading processes. Superheated steam is generated in the MHR steam generator at 165.5 (bar) and 538 °C. A fraction of the generated steam (147 kg/s) is diverted to a noncondensing turbine generator with gross[22] output of 101 MW_e. The balance of the steam (439 kg/s) is assumed to be used for field injection. However, injection steam is only required at a pressure of 138 bar (336 °C). The required steam conditions by the field are obtained by throttling and the de-superheating of the HP steam. In this configuration, the plant is capable of producing 238,500 bspd. Rao and McMain assumed that this amount of steam is sufficient to meet the steam requirements of a 46,000 bopd project i.e. SOR of roughly 5.2.

Dieter et al (2006) studied the potential of using helium-cooled, graphite-moderated reactors PBMR for the production of steam for various high-temperature industrial processes. Depending on the cycle configuration, their analysis show that this type of reactor is capable of producing process steam at temperature of 420 °C and pressure in the range 40-180 bar, a range which is compatible with most heavy oil projects found today. Other studies that discussed the advantage of high-temperature gas-cooled reactors specifically for heavy oil projects include (Djokolelono, et al., 1988)(Hernan, 1989)(Hernan, 1991)(Barnet, et al., 1991)(IAEA, 2001)(Badruzzaman, et al., 2008).

[22]The net output is 64 $MW_{e.}$ the difference is used to drive the MHR circulators, the feed and condensate pumps, and other non-processes auxiliaries.

The economics of PBMR to supply high pressure steam for SAGD operations were evaluated by Reine, et al. (2006). The study involved a team of experts from four different companies to work on conceptual designs that will allow the utilization of PBMR for process heat applications, including oil sands extraction. They compared the costs of PBMR-generated steam with that from gas-fired boilers. They estimated that the cost of PBMR-generated steam at about \$ 21.7/m^3 of steam. They concluded that PBMR-generated steam could become cost competitive with gas-fired boilers at natural gas prices above \$7/MMBtu[23].

A more recent study by Finan and Kadak (2010) indicated that PBMR-generated steam could become cost competitive at natural gas prices above \$6.08/MMBtu. Differences in calculated natural gas breakeven price in these two studies can be attributed mainly to different economic assumptions used.

Another important consideration is whether the sizes, in terms of steam output, of existing commercial reactors match steam loads of heavy oil projects. In order to capture the economics of scale, nuclear power plants are often designed to be large so that capital investment is spread over larger output. The large sizes of existing nuclear reactors, therefore, poses further challenges to the integration of this technology into heavy oil production.

Considering for example the Enhanced CANDU 6 (EC6)[24], one of the smallest commercially available nuclear reactors. When configured for 100% steam production, this plant is capable of producing enough steam for a 200,000 bopd project, based on SOR of 2.5 (McColl, et al., 2008). An EOR project of this size is considered too large by today's standard. As in 2008, the Duri Thermal Project in Indonesia which is the world's largest EOR project was producing 190,000 bopd (Guntis, 2008). The second and third largest EOR projects are the Cold Lack CSS project in Canada and the Kern River Steamflood in California with production capacities of 154,000 bopd 86,000 bopd respectively (Guntis, 2008). These are mega projects and most EOR projects are much smaller in size. To complicate matters further, there are many signs that oil companies

[23]The price above which the nuclear plant would be more economic than the reference gas-fired facility

[24] The EC6 was actively considered for oil sands projects in 2006.

have learned the lesson of the oil price crash in 2008 and they are now adopting to develop large field incrementally. In this case, instead of targeting 100,000-200,000 bopd projects, companies are opting for more sustainable passage to growth in 10,000-20,000 bopd steps (Nicholls, 2010). The issue of relatively large thermal output from existing nuclear reactors can be partially offset by operating in a cogeneration scheme where part of the produced steam is used to generate power. The ability to generate excess electricity and sell it for additional revenue will primarily depend on whether there is a market for the excess electricity.

Another challenge facing the integration of nuclear to heavy oil projects is that high temperature steam can only be transported, economically, for short distances, 10-15 km (Doucet, 2007). (Finan, et al., 2010). This would imply that the nuclear facility would have to be located within a close proximity to heavy oil operations, which may not be suitable for the construction of nuclear facilities.

Oil companies are also unfamiliar with nuclear development and operation. Oil companies and host governments may have to involve other companies to construct and operate their proposed nuclear facilities. This could significantly alter the project economics. Furthermore, the complexity of EOR projects means that heavy oil developments carry higher-than-average geological and engineering risks as compared to conventional oil developments. Heavy oil developers may be reluctant to embark on further risky investments which includes the decision to build large nuclear steam plants costing $billion-plus that face unpredictable technological, regulatory, and political risks.

4.3.3 Case Studies

Indonesia Heavy Oil

A prefeasibility study of using High Temperature Reactor (HTR) module to supply injection steam to the Duri steamflood project was completed in 1987 and was later reported by Djokolelono, et al(1988). Production from the field peaked in 1994 at 300,000 bopd, with daily steam injection rate between 604,000 -755,000 bspd. It was estimated that four 200MWt-HTR units would be required to meet the base steam load. The study compared the economics of HTR with the costs of generating steam using oil-fired boilers. For the latter option, it was estimated that about 20% of the produced oil would be consumed for steam generation. The study concluded that the very low oil prices, around $18/bbl at the time of the study, made it hard for the nuclear option to compete against oil-fired facility.

In addition the study investigated the influence of the petroleum fiscal arrangement agreed between the oil company and the host government on the feasibility of the nuclear option. Given the large amount capital involved in the construction of nuclear plants, the decision making process was found to be very sensitive to the fiscal parameters such as corporate tax, government profit share, and company profit share. This is because any potential saving from adopting the nuclear technology will have to be shared between the host government and the oil company[25].

No further work has been published since the 1987 study but results therein were further discussed by Rahman, et al. (1995) and Lasman, et al. (1996). Perhaps, the lack of interest for nuclear case was lost by the decision to build a 300 MW gas-fired cogeneration plant in 1998 in the North Duri field, supplying up to 300 megawatts of electrical power as well as steam to the Duri steamflood project (Chevron, 2010).

Venezuelan Extra-heavy Oil

The Orinoco Oil Belt, OOB, in Venezuela contains the world's largest deposits of extra-heavy oil. Venezuela alone has 1.9 trillion barrels of discovered original oil-in-place (World Energy Council, 2010). Substantial amount of energy would be needed unlock these vast resources, with heavy economic and environmental burdens. The possibility of using HTGR as the main energy source for the extraction and upgrading of OOB heavy oil was investigated in a series of studies by Hernan (1989, 1991, 1992). Hernan proposed the use of three 1200 MW_{th} HTGR to supply steam for a 100,000 bopd project. The selection of advanced HTGR was based on the fact the proposed field requires saturated steam at a pressure of 120-170 bar; a pressure level that cannot be obtained by any other conventional reactors particularly water-cooled reactors (Hernan, 1992). Furthermore, superheated steam (500°C) at 100 bar is required for crude oil upgrading to synthetic oil.

[25] Background on petroleum fiscal system and its impacts on energy efficiency investment are discussed in chapter.

The studies concluded that advanced HTGRs are technically capable of delivering the steam requirements for the majority of proposed OOB developments. However, the studies did not include any economic evaluations neither they compared it with other conventional steam generation methods. It was, however, indicated that oil prices and market conditions at the time of the studies did not favour heavy oil investments, let alone investment in highly capital-intensive and complex nuclear facilities.

The interest in unclear energy has been renewed but this time using a small scale Argentinean CAREM reactor being developed by the National Atomic Energy Commission (CNEA) and (Berry, 2009). The reactor is based on a simplified PWR design with 100 MW_{th} and 25 MW_e (U.S. Department of Energy, 2001). However, despite all interests the fact remains that nuclear in OOB is still conceptual and whether any of the proposed concepts will one day materialize is uncertain.

Canadian Oil Sands

. Natural gas consumption in the oil sands operations represent about 20 percent of Canadian natural gas demand, and it is predicted to grow to 25-40 percent by 2035 (IHS & CERA, 2009). Canada has also been under scrutiny to lower GHG emissions from its oil sands industry. Therefore, Canada has been actively involved over the past four decades in evaluating the nuclear option to power its growing oil sands industry.

The use of CANDU nuclear reactor was first discussed in 1973 (National Energy Board, 2004). One of the earliest study was conducted by Atomic Energy of Canada Limited (AECL) (Puitagunta, et al., 1977). The study compared the economics of an organic-cooled version of CANDU (CANDU-OCR) with fossil-fired facilities to supply both electricity and steam for oil sands extraction and upgrading processes. The, then, conceptual CANDU-OCR was chosen because the output steam conditions from the commercial CANDU reactor was found to be too low for most tar sands projects. CANDU-ORC coolant operates at a maximum temperature of 400°C, allowing high pressure steam to be generated. Given the large capital investment required for nuclear development, the study found that the cost of steam from the CANDU-OCR is strongly dependent on the type of project financing. Factors such as low interest rates, continuous fuel cost escalation, high plant capacity, and long write-off period were found to improve the economic prospects of the nuclear option. Unfortunately, the CANDU-OCR reactor development program was later cancelled by AECl, and only an experimental reactor was ever built.

In a renewed interest, AECL and the Canadian Energy Research Institute (CERI) carried out a joint study to evaluate the economics CANDU-based cogeneration for oil sands extraction and upgrading processes (Dunbar, et al., 2003). The economics of a modified ACR-700^{TM} Advanced CANDU Reactor with a 731 MW_e (1983 MW_{th}) was compared with a gas-fired cogeneration plant. Excess electricity from the plant is assumed to be sold to the grid at $50/MWh. The study assumed that the ACR-700^{TM}can produce steam at sufficiently high temperature and pressure for SAGD operations. Based on their assumptions, the study indicated that the nuclear option is cost competitive with a gas fired cogeneration plant at natural gas price of 3.5 US$/MMBtu, see Table 4-6.

Not surprisingly, the cost of the steam from the nuclear plant was found to be very sensitive to the capital cost of the facility. A 25% increase in capital cost would increase the steam cost from \$ 8.61/m^3 to \$10.31/m^3. On the other hand, the cost of steam from the gas fired facility was more sensitive to natural gas prices as well as any possible emissions compliance cost. An emission compliance cost of $15 per tonne of CO_2 emitted would increase the steam cost from \$8.71/m^3 to \$10.29/m^3.

It is worth mentioning that in this study the ACR-700^{TM} was configured to produce both electricity (100 MW) and steam (392,500 bspd) in a cogeneration scheme. The steam capability of this reactor would have been much larger if it was configured for process steam generation only. Furthermore, the study proposed the use of additional steam loop where the steam from the reactor's secondary loop exchanges heat in "a saline water boiler" to generate the required 80% quality steam, instead of using steam directly from the reactor's steam generator. This resulted in the steam being generated at pressure (29 barg). The study, however, failed to recognise that this pressure level is considered low for most SAGD operations found today. In fact, the ACR-700^{TM}was discounted, as a technically feasible reactor, in a more recent study by Finan et al (2010).

Table 4-6: Steam Costs: Nuclear vs. Natural Gas (Dunbar, et al., 2003)

Cost Category	Nuclear	Gas-fired Cogeneration
Cost per Tons of Oil ($/t)		
• Fixed Capital	6.71	0.96
• Working Capital	0.07	0.01
• Fuel	0.02	8.98
• Spent Fuel Management	0.28	0.00
• Other O&M Costs	3.07	0.30
• Subtotal	10.2	10.3
• Credit for Surplus Electricity Sale	1.54	1.54
• ***Total Net Cost***	***8.61***	***8.71***

More recently, CERI has released a study[26] examining various fuel alternatives that could be commercially deployed in oil sands operations. In part III of the study, the supply costs of the nuclear option was evaluated (McColl, et al., 2008). The use of Enhanced CANDU 6 reactor was dismissed because the outlet steam pressure this is insufficient for most oil sands project. The ACR-1000 and the EPR 1600 (a light water reactor from AREVA) have also been considered in the study. The ACR-1000 is capable of delivering steam at temperature of 275.5 °C and a pressure of 59 barg, while the EPR 1600 can produce steam at higher temperature and pressure, 564 °C and 76 barg. The study, however, suggested that these reactors are too large for almost all proposed oil sands developments because they require 275,000-388,000 bopd projects.

As an alternative, the study indicates that high temperature gas cooled reactors such as PBMR and liquid metal cooled reactors (such as Toshiba 4S) are more likely to be used in S-EOR projects. Approximately, 12 Toshiba 4S unites would be required for a 30,000 bopd project. The study estimated that steam from the 4S could cost as much as C$19/GJ (2007 Canadian dollar).

[26] The study is published in four parts and is entitled "Green Bitumen: The Role of Nuclear, Gasification, and CCS in Alberta's Oil Sands"

Finan and Kadak (2010) studied the economics and potential GHG avoidance of using two Canadian nuclear reactors (EC6 and ACR-700) and the PBMR for the oil sands. Again, the EC6 was dismissed for its relatively low steam pressure output. Although the ACR-700 can produce steam at higher pressure than the EC6, the study indicates that this reactor is too large (697,872 bopd) for most oil and projects and would require a 200,000+ bopd project. It is worth noting that the ACR-700™ steam capabilities reported in this study is almost two-fold the value reported in the CERI 2003 study and discussed earlier. This is because in the latter study all the produced steam is used for field injection whereas in the 2003 part of the total steam is diverted to a steam turbine for power generation in a cogeneration mode. Based on simple heat losses and pressure drop, Finan and Kadak estimated that steam from the ACR-700 can be feasibly transported only within a 10 km radius. However, a 200,000+ project is likely to spread over much radius, imposing further complication to utilization of this reactor for field injection application. Similar conclusion was reached regarding EC6 reactor.

Another type of reactors considered in the study was the modular Pebble Bed Modular Reactor (PBMR). PBMR is high-temperature gas-cooled reactor that has a passive safety features and on-line refuelling capabilities. The outlet temperature from the core of the PBMR is in excess of 750 °C, allowing the production of high pressure and temperature steam for power generation and process applications. Based on the assumptions considered in the study, steam supply capabilities[27] of one PBMR module are shown in Table 4-7. Depending on the field's SOR, this reactor can meet the steam requirements of a 40,000-65,000 bopd project, well within project sizes found today. Multiple installations can be used for larger projects.

[27] The actual steam output depends on the steam generator and separator designs which are determined by the required steam conditions.

Table 4-7: PBMR steam supply capability (Finan, et al., 2010)

Steam Pressure (bar)	Steam Temperature (C)	Steam Quality (%)	Steam Rate (bspd)
110	310	100	130,000

Finan and Kadak analyzed in details the economics of PBMR for two scenarios: 100% electricity generation and 100% steam production. In the first scenario, they compared the electricity supply cost of PBMR with a 100 MW_e combined cycle gas turbine CCGT plant fired on natural. They showed that the breakeven natural gas price is $11.40/MMBtu[28] for electricity production. In the second scenario, they compared the economics of PBMR-generated steam with natural gas-fired boilers. The PBMR-generated steam was found to be cost competitive at natural gas prices above $6.08/MMBtu. Natural gas price around the time of the study in 2008 was about $9/MMBtu. However, natural gas prices collapsed since 2008. For reference, the January 2011 average NYMEX gas price was about $3.96/MMBtu; well below the breakeven price for the nuclear-generated steam. It is also worth noting that the breakeven price required to make the nuclear option cost competitive with gas-fired facility is lowered for the process steam scenario than the power generation scenario. This implies that nuclear could become cost-effective for steam generation even if it is not for electricity generation.

Despite the many studies that indicated the economic attractiveness of the nuclear option, a nuclear facility in the Canadian Oil Sands is yet to be commercially demonstrated. In fact, in 2007 a Canadian parliamentary committee advised that any plans for nuclear power plants to supply electricity and steam to the Alberta oil sands should be put on hold until the full repercussions of using the technology are known[29].

[28] Prices were reported in Canadian dollars but the study used an exchange rate of 0.9 USD per CAD to convert from Canadian to US dollar

[29] Reuters: "Canada wary of nuclear power for oil sands" March 28 Wed Mar 28, 2007 10:58pm BST

4.3.4 Remarks on Nuclear for S-EOR

Beside the typical financial, economics, institutional hurdles that are facing the nuclear industry, the special nature of heavy oil projects imposes further challenges to the integration of nuclear energy into S-EOR projects. These include:

- Steam conditions, particularly steam pressure, are incompatible with field's requirements
- Plant Size is too large for most S-EOR found today or those proposed for future development
- The difficulty in transporting high temperature steam requires nuclear plants to be located in a very close proximity to the thermal host

Furthermore, the public attitudes toward the safety risk and the disposal of nuclear waste remain ambiguous, with significant opposition. The reputation of nuclear energy has also taken a big hit recently with the crisis unfolding in Japan. While the earthquake apparently did not do too much damage to the reactor, a 10-meter tsunami wave defunctionalized back-up power needed to drive reactor cooling pumps. With no way to pump water to cool the reactors, fuel rods in the core of the reactors started to overheat, sending radiation into the atmosphere. Nuclear energy was just starting to regain ground in the world given the public interest in clean abundant and cheap energy. This nuclear renaissance is now in danger as the nuclear industry is going to have to address real safety issues and concerns arising from unforeseen catastrophic events. Just saying it is safe won't work anymore. The role of nuclear energy in unconventional oil development is therefore bleak.

5 Multidisciplinary Evaluation: Framework and Modules

5.1 Overview

As outlined in section 1.7, the decision-making process in S-EOR developments and operations require incorporating surface, subsurface, economic, financial, and risk evaluation, demanding complex multidisciplinary team efforts. EOR project evaluation typically proceeds from reservoir screening through prospective simulations, detailed appraisal, and then project implementation and surveillance. These evaluation steps, although done systematically, are typically carried out by separate teams who are often constrained by inputs from previous evaluations.

The economic viability of S-EOR projects is generally governed by the time-rate of recovery of oil versus the time-rate of expenses required to recover this oil. For many heavy oil developers, however, preliminary development phases typically focus on maximizing oil rate and not to optimize long run economics. This development strategy could lead to suboptimum decision-making, as it will be quantitatively demonstrated subsequent chapters.

This chapter reports on the development of a multidisciplinary and integrated model to enhance the decision-making processes involved in the evaluation of S-EOR projects. The model consists of the following modules:

- Steam Injection Module (Subsurface)
- Thermal Performance Module (Surface)
- Engineering Economic Module
- Petroleum Fiscal Module
- Risk Module

The integrated modules form a Techno-economic, Environmental, and Risk Model (TERM) that can be used for S-EOR evaluations. The model is refereed to hereafter as TERM-EOR. For brevity, this chapter provides only overviews of the separate modules and their main inputs and outputs. Additional details are also available in Chapters Six and Seven where TERM-EOR is used in two case studies.

5.2 Steam Injection Module

Thermal recovery processes such as steamflooding and SAGD involve heat and mass transport in porous media which can be described mathematically with a set of coupled differential equations (Hong, 1993). The complexity of these equations means that they can only be solved by means of numerical simulations. The problem with numerical simulations is that they usually require extensive information about the reservoir and lengthy computational time.

Simplified analytical and semi-analytical models that yield acceptable results have been developed for quick and easy reservoir screening. Four models are adopted in this study:

- Marx-Langenheim Model – Steamflood
- Reis Model- SAGD
- Neuman Model (Gravity Override in Steamflood)
- Butler Model- SAGD

The last two models can be readily integrated, as described in the original papers, to TERM-EOR. For this reason, these two models are not described in this thesis. Detailed derivations of Butler SAGD model and Neuman steamflooding model can be found in (Butler, 1980) and (Hong, 1993), respectively. Some re-arrangements and in some cases further derivations of the original forms were required on the first two models to make them compatible with TERM-EOR hierarchy. These two models are described here.

5.2.1 Reis SAGD Model

Reis (1992) developed predictive model for SAGD process. His model is basically an improved representation of Bulter's original SAGD model described in (Butler, 1980). The model predicts both the oil rate as well the latent heat requirements. A derivation for the SOR is also provided. The most representative equations are presented here and more details can be found in the original paper.

Reis (1992) gives the cumulative oil production per unit length along the horizontal well as:

Equation 5-1

Where,

Cumulative oil production per, m^3/m

Porosity

Initial oil saturation minus residual oil saturation to steam

Effective oil permeability, μm^2

Acceleration of gravity, m/d^2

Thickness of formation, m

Dimensionless temperature coefficient,

Kinematic viscosity at steam temperature

Dimensionless viscosity coefficient

Time since start of steam injection

It is clear from Equation 5-1 that the oil rate is predicted to be inversely proportional to the square root of oil viscosity at steam temperature (, and directly proportional to the thickness of the reservoir (*H)*.

The total steam injection rate of latent heat required to maintain the oil drainage rate at its maximum value along one side of the steam zone can be obtained by the following expression:

Equation 5-2

Where,

Latent heat enthalpy injection rate, J/d.m

Formation heat capacity, J/°C.m^3

Temperature difference, $T_s - T_i$, °C.

Thermal diffusivity, m^2/d

Once the latent heat requirements are known, the steam injection rate in CWE can be determined based on Equation 5-3:

Equation 5-3

Where,

Steam injection rate (cold water equivalent), m^3/d

Water density, kg/m^3

Latent heat of steam, kJ/gm

Steam quality

Finally, the SOR profile can be obtained using Equation 5-4:

Equation 5-4

Because neither steam injection pressure nor steam temperature appears in Equation 5-1 but they are reflected in the kinematic viscosity at steam temperature , the current model is modified to accept injection pressure and steam quality as inputs. Using steam properties functions built into TERM-EOR, other steam properties such as saturation temperature and enthalpy are calculated and inputted into the model.

The kinematic viscosity is then determined based on the steam temperature. Kinematic viscosity versus temperature depends on the oil properties and it is field specific. It is therefore important to use the right data in the analysis. Published viscosity data for a Cold Lake bitumen sample described by Anil, et al(1987) is used in this study.

5.2.2 Marx-Langenheim Steamflooding Model[30]

The Marx andLangenheim (1959) steamflooding model is a frontal displacement model. This mode predictes the growth of steam zone that is limited in itsgrowthrateby the loss of heat to the overburdenandunderbudernandby the rate at whichsteam is intorduced. Butler (1991) gives the cumulativeheated area at time t as:

Equation 5-5

Where,

Equation 5-6

erfc (x)	Complementary error function defined as
	Constant heat injection rate, J/s
$P_{1,2}$	Reservoir and overburden rock grain density, kg/m^3
C_1	Dry rock specific heat, J/kg/K
T_s	Saturation temperature, °C
T_r	Initial reservoir temperature, °C
K	Overburden thermal conductivity, W/ (K·m)
h	Reservoir Height

The rate of growth of the heated zone can be obtained differentiation of Equation 5-5 with respect to time:

Equation 5-7

[30]Further derivations of the cumulative and instantaneous SOR were required. These have been done with the advice and help of Dr Ton Van Heel of Shell Technology Oman.

The volumetric rate at which oil is displaced is obtained by multiplying the rate of increase of the volume of the steam chamber by its porosity and by the change in oil saturation:

Equation 5-8

Where,

q_o Oil Rate ,m^3/s

ϕ Formation Porosity

S_o Initial oil saturation

S_{or} Residual oil saturation

The cumulative oil displaced is then given by:

Marx-Langenheim model assumes constant rate of heat-injection (H_0)

Equation 5-9

Where,

q_{st} Steam-injection rate (m3/s)

Steam quality

h_s Enthalpy of steam

h_f Enthalpy of the liquid (at steam-temperature)

$h_f(T_{res})$ Enthalpy of the liquid at reservoir temperature

Rewriting Equation 5-9 to obtain the volumetric steam-injection rate as:

Equation 5-10

From Equations 5-8 & 5-10, the instantaneous SOR can be obtained:

Equation 5-11

And the cumulative SOR is:

It is worth mentioning here that one of the limitations of Marx andLangenheim model is thatitassumesconstat heat injection. Therefore, itcannotbeusedfor cases wheresteaminjectionrate is varying.

5.2.3 Numerical Simulations

Reservoir engineers also make use of sophisticated thermal reservoir numerical tools. These numerical tools, although expensive and require long computation time, are more robust and accurate in the way they model the actual physical and geomechanical phenomena happening during steam injection. An example of these tools is STARS, from Computer Modeling Group CMG LTD[31].

TERM-EOR is built to accept inputs from such tools. In this case, only three parameters are required:

- Steam rate, m^3/day
- Injection pressure
- Oil rate, m^3/day

[31]www.cmgroup.com

5.3 Surface Thermal Performance Module

Robust modelling of surface steam facility is indispensible for the successful evaluation of energy-intensive processes such S-EOR projects. Once the required steam conditions and rates are determined, analytically or numerically, the amount of fuel needed to generate the required steam must be estimated. In cogeneration systems, additional inputs about the gas turbine load are required. There are a large number of different steam technologies and plant configurations, and plant control that surface steam facilities in T-EOR can take. Therefore, there is a need for a versatile and flexible tool to simulate these systems accurately. Additional important perquisite is that this tool must be effectively integrated to TERM-EOR for effective utilization.

Thermoflex process simulator of Thermoflow Inc[32] has been selected in this study. Thermoflex is a user-friendly and fully flexible program that allows the modelling of a broad range of thermal systems, with emphasis on power generation and cogeneration. Thermoflex is completely modular, with each component represented by an icon and modelled by its own self-contained subroutine. Furthermore, Thermoflex provides design and off-design modes into a single program. This feature is particularly important for components that have quite differently at off-design from their design such as gas turbines and HRSGs.

An important feature of Thermoflex in regards to this study is the E-LINK utility that comes with Thermoflex. E-LINK allows Thermoflex to be run from with Excel. Once the baseline model is designed, cycle optimizations and what-if- simulations can be conducted without the need to use the original file. Some of the main inputs from other TERM-ERO modules to Thermoflex include:

- Steam injection profile
- Steam conditions (pressure and quality)
- ISO conditions
- Steam plant control
- Gas turbine load (for cogeneration based systems)

[32] www.thermoflow.com

5.4 Petroleum Economic Module

Economic analysis is particularly important in S-EOR projects since such projects are high investment and low profit operations. In addition, heavy crude fetches a lower price that lighter crudes.

Once the steam injection and oil production schedules have been determined and the amount of fuel required to produce the steam is estimated, it is possible to perform an economic analysis to check the economic viability of the proposed operation. The most useful of economic measure is perhaps the Net Present Value (NPV) which is described in the following section.

5.4.1 Net Present Value

One of the most fundamental principles in finance is that a dollar received today worth more than a dollar received in the future. This is because (Khatib, 2003):

- Future incomes are eroded by inflation and thus money in the future has lower purchasing power than today's money.
- The existence of risk. Future income or expenditure may vary from anticipated values.
- A dollar received today can be invested to earn interest. By undertaking investment and foregoing expenditure, an investor expects to be rewarded by a return in the future

Projects in the oil & gas industry live for a long time. For S-EOR projects most expenditure, in the form of operating costs (fuel, etc.) and income (oil sale) occurs after commissioning. Thus, such future financial flows will be incurred during different time and circumstances, thus will have different value of money than flows occurring during project evaluation. This makes the time value of money (discounting) and the proper choice of discount rate critical to the evaluation of capital-intensive lone-life projects with higher than above than average operational cost, like those in S-EOR projects.

Therefore, a method is needed to convert a delayed payoff into a value of today, a present value. Present valuing (PV) of a future financial outlay (C) is carried out through multiplying it by a discount factor (DF), which is less than 1. If it was more than one then the dollar in the future would be worth than the dollar today. The PV can be determined using the following equation:

Where DF_i and C_i are the discount factor and cash flow at time t_i. The discount factor is given by:

Where r_i is the rate of return that would be offered by other comparable investment at time t_i.

The NPV is obtained by adding the initial cash flow for the project which is usually a negative number to the PV of the individual cash flows. The NPV is given by:

Where n is the project life.

Using NPV as an evaluation criterion requires that the project NPV has to be greater than zero. This implies that the PV of nay future incomes is greater than the initial and future discounted outcomes required for the project.

5.4.2 S-EOR projects Cash Flow Analysis

Calculating the NPV of a series of cash flows requires those cash flows to be initially known and determined. For S-EOR projects, these cash flows are given by:

The *net* oil is used here because in the case where crude oil is used for steam generation some of the produced oil is consumed on-site and thus not available for sale.

Once the project gross revenue is determined, the net revenue is given by:

The cost for S-EOR projects can be broadly divided into cost related to the development of the projects and costs related to operations. Development costs include expenditure for the installation of hydrocarbon facilities, drilling wells, steam generation and water treatment equipments.

Data used in the study are taken from the comprehensive studies conducted by the Canadian Energy Research Institute (Nicole, et al., 2005) and (Nicole, et al., 2006). The data presented in these two reports are for SAGD and CSS projects in the Canadian oil sands.

Additional, and more up to date, data are obtained for CSS and steamflood projects under development in Oman. This data, although used in the economic analysis presented in Chapters Six and Seven, are not included in this thesis for confidentiality. The economic data is organized in terms of $/bbl of oil and $\$/m^3$ of steam and tabulated in the economic spreadsheet so that capital investment can be scaled to fit the size of the project in consideration.

On the other hand, operating cost include fuel costs, water treatment cost, operation and maintenance (O&M), electricity charge, emissions tax etc.

Many of the inputs required for determining project capital and operating costs depend on the output from subsurface module (oil and steam rates) and surface module (fuel, number of steam generators etc).

5.4.3 S-EOR Economic and Environmental Indicators

Some of the most important outputs from the economic module are explained here:

- **Net Oil**: this is simply the yearly produced oil minus the oil used for steam generation. This indicator is important only when crude oil is used for steam generation.

- **Discounted Oil**: the net annual oil production is discounted based on the discount factor of that year. This can be a good and quick to-calculate economic indicator that could be used to compare two projects or operating scenarios that broadly different in oil schedules only. If capital or/and capital costs are expected to significantly change due to changes in oil schedules, then this indicator could mislead the decision-making process.

- **Gas Consumption:** gas consumption per m^3 of steam, gas consumption per barrel of oil, life-cycle natural gas consumptions are presented as an output from the economic modules. The first parameter reflects on the efficiency of surface facility whereas the latter two parameters are influence by both surface and subsurface factors. It is thus important that they are not confused with each others.

- **CO_2 Emissions**: CO_2 emissions per barrel of oil, CO_2 emission per m^3 of steam, life-cycle CO_2emissions.

- **Total cost per barrel of oil**: this is the total capital and operating costs including steam and non-steam cost components expressed in $/bbl.

- **Acceptable SOR**: this study proposes the use of an economic indicator referred to as 'acceptable SOR' as an improved alternative to the standard SOR. The use of an alternative indicator is encouraged by the lack of consistency of the actual SOR, as discussed in section 3.5. The acceptable SOR is obtained by specifying an operating cost target. Then the acceptable SOR becomes the SOR that can be tolerated above which the targeted operating cost is exceeded. The acceptable SOR is determined by the operating cost calculated by the economic module. The operating cost is in turn influenced by the required steam conditions, steam generation technology, fuel cost, emission cost etc. this makes the acceptable SOR a dynamic indicator that reflects on both surface and subsurface factors.

5.4.4 Costs of Generating Electricity

Cogeneration is being widely adopted by unconventional oil producers to cut natural gas costs. Electricity is produced as a by-product from the cogeneration plant. As it will be discussed in Chapter Six, large amount of electricity is typically produced from cogeneration systems operating in S-EOR projects. Excess electricity can be used on-site to support other non-EOR activities or be sold to the national grid for additional revenue to the project. Accurate estimation of the costs of generating electricity is vital to the effective evaluation, and later operation, of cogeneration systems. For reasons explained in Chapter Six, only gas turbine-based cogeneration systems are considered in this study.

The up-front capital investment is converted into a stream of equal annual payments using the concept of *capital recovery factor*(CRF). CRF simply converts a present value into a stream of equal annual payments over a specified time, at a specified discount rate (Khatib, 2003). CRF is given by:

The data required to estimate the capital cost for gas turbine power plants is obtained from (Energy Market Authority , 2004), (ESMAP, 2008), (IMO, 2009), (PDO, 2010), (Gas Turbine World Handbook , 2010). The latter sources include an annually updated price list of commercial gas turbine packages from different manufactures. The 2010 list is tabulated (in $/kW installed) and impeded into the economic module. The price of the selected gas turbine is then interpolated from the list by inputting the gas turbine size in kW. Balance-of-plant equipments not reported in the Gas Turbine World Handbook are obtained from the other sources given.

Furthermore, parameters required for fuel, O&M, and emission costs calculations are obtained from the Thermoflex process simulator.

5.4.4.1 Levelized Cost of Electricity

An additional economic indicator for the evaluation of electricity generation is the *Levelized Cost of Electricity* (LCOE). The LCOE is that cost that, if assigned to every unit of electricity produced by the system over the analysis period, will equal the total life cycle cost (TLCC) when discounted back to the base year(NREL, 1995). In other words, if every unit of electricity produced is sold at the calculated LCOE, the project would precisely break even and the NPV would be zero.

The formula that is used to calculate the LCOE should include all operating costs of the project under consideration. In this study, the following expression is used which is designed to include capital cost, depreciation, annual costs, and emission cost (if there is any). In addition, the LCOE is determined in after-tax basis.

The LCOE is based on two important assumptions (OECD, 2010):

- The interest rate ‘r’ used for discounting both costs and revenues does not vary during the lifetime of the project under consideration.
- The electricity price is stable and does not change during the lifetime of the project.

Despite these shortcomings, LCOE remains widely used tool for comparing the costs of different power generation technologies or from the same technologies but at different operating scenario.

The use of LCOE is demonstrated in Chapter Six of this thesis.

5.5 Petroleum Fiscal Module

5.5.1 Introduction

Once the gross revenue is obtained, as outlined in section 5.4, the next question will be how to split this revenue. This is because it is typical in the oil and gas industry that the host government, as the owner of the hydrocarbon, engages an international oil company IOC as a contractor to provide financial and technical services for exploration and development operations. IOC involvement is mainly driven by the fact that host governments, particularly in developing countries, lack technical expertise (know-how) and capital requirements needed to support capital-intensive and technologically-complex exploration and development operations.

Governments also appreciate the fact that oil exploration is inherently risky activity. Nine out of ten exploration efforts are not successful (Kenneth, 2008). In such investment environment, governments are understandably reluctant to spend their limited capital, needed for other social developments, on oil exploration and development. In contrast, large international oil firms are often considered risk-takers who are theoretically more capable of diversifying their risk than governments when it comes to oil exploration and developments. In rewards for its risk taken and services rendered, oil companies acquire a share of the produced hydrocarbons (in kind) or a share of the revenues generated by selling the produced hydrocarbons. Shares are allocated in accordance with the country’s petroleum fiscal system. In this case, the host government is faced with the difficult task of designing an efficient fiscal system whereby it maximizes its share of the produced hydrocarbons as well as sufficiently rewards the oil company for its services and risk taking.

Almost under all fiscal systems, oil companies are allowed to recoup their expenditures (CAPEX and OPEX) provided that sufficient revenue is generated. There is, hence, a clear alignment of interest between host governments and oil companies to keep costs as low as possible. Host governments are interested in maximizing revenues from its natural resources while oil companies are keen to keep costs down so that sufficient revenues are generated that will allow them to reclaim their expenditures and get adequate share of the profit.

It is clear that everyone benefits if cost is kept down. Most fiscal systems around the world are well designed in this regards and it is hard to find a system where there is not incentives to cut costs (Johnston, 2004). If a dollar in saved, then there is an extra dollar of profit. Because the extra profit is shared between the oil company and the host government, a question one must simply ask is who benefit from this saving and by how much(Johnston, 2004).

The answer to this question lies in the terms and parameters of the petroleum fiscal system. The fiscal system in place dictates how much each party receives on a dollar saved and, hence, results in varying degrees of incentives available for each party to keep costs down. In Indonesia, a county known for its tough petroleum fiscal system, under the standard oil contract, the oil company receives only about 15 cents on a dollar saved and the governments reaps the remaining 85 cents. In contrast, an oil company operating in the UK receives up to 69-75 cents on the dollar saved(Johnston 2003). If the saving index is very low then the incentives for the oil company to cut costs is somewhat mitigated. It is, therefore, in the interest of the host government that such inefficiencies in the fiscal system are eliminated.

Cost saving is particulate important in S-EOR projects where both capital and operating expenses are high. There is therefore a large potential savings, but are there enough incentives available to the oil company to do so.

As it will be demonstrated in Chapters Six and Seven, a project that is profitable from a government point of view may or may not be profitable from any oil company's prospective. In this study, the influence of fiscal system parameters and terms on the economic prospective and, hence, the level of incentives available to the oil company to invest on S-EOR projects in general and on energy efficiency measures in particular is investigated. This is achieved by incorporating various fiscal systems into the discounted cash flow model described in section 5.6. An overview of petroleum fiscal systems and the module adopted in this study are described next.

5.5.2 Overview of Petroleum Fiscal Systems

Of the numerous types of fiscal systems in the world today, there are essentially two basic themes that fall under two main families, concessionary (tax and royalty) and contractual system (Johnston 2003). The taxonomy of the petroleum fiscal system is outlined in Figure 5-1, adapted from Johnston (2003).

The fundamental distinction between the concessionary and contractual system is mainly attributed to the ownership of the hydrocarbons. Under the contractual systems, the oil company holds the title to the hydrocarbon, against which it pays royalties and taxes to the host government. In contrast, the title to the hydrocarbon is retained by the host government under contractual systems. The latter type of fiscal system is known as Production Sharing Contracts (PSC). Under PSC, the oil company finances and carries out all petroleum operations and consequently receives an amount of hydrocarbon for the recovery of its costs as well as amount of hydrocarbon that represent a share of the profit.

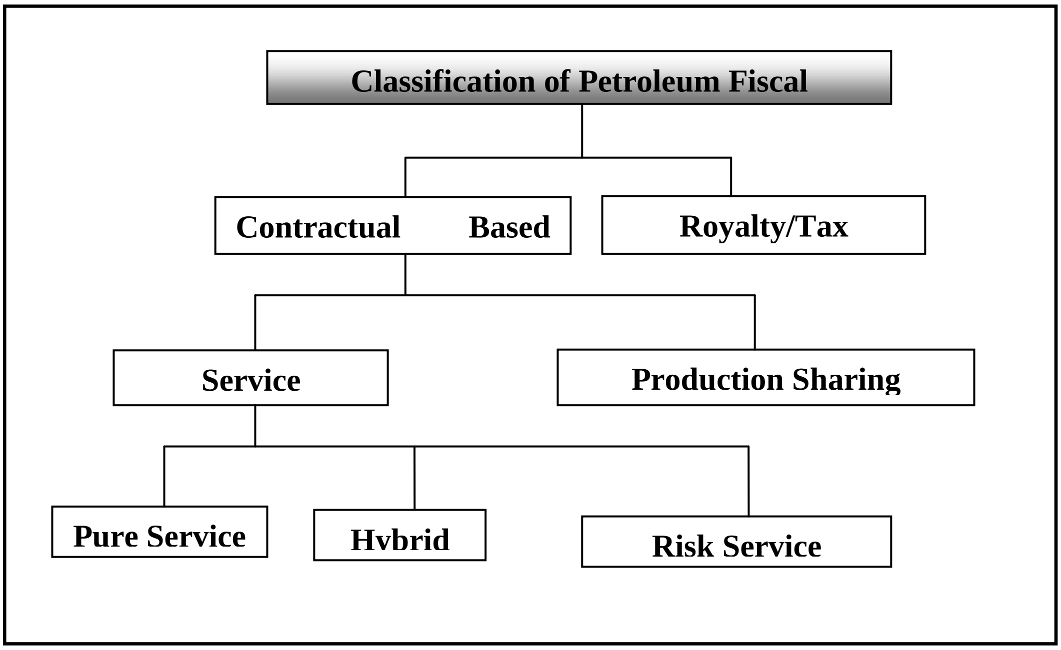


Figure 5-1: Classification of Petroleum Fiscal Systems

In a pure (non-risk) service contract, the oil company carries out exploration/or development work on behalf of the host government for a flat pre-agreed fee. This type of agreement is very similar to the oil service industry where the contractor is paid a fee for carrying out a service. Host government typically opt for this option when it is selfsufficient in terms of expertise (know-how) and capital requirements needed to support its exploration and development projects. Under risk service agreements, the oil company is reimbursed based on profit (risk) rather than a flat fee as in pure service contract. As with concessionary and PSC, the oil company under risk service contracts is responsible for providing all capital associated with exploration and development but is entitled for a share of the profit , not the production, and therefore it is not entirely a PSC. In this case, the oil company bears all the risk but has a potential of profit. These types of agreements are rare and currently exist in Mexico and Iran (Pedro, 2008).

More details on petroleum fiscal arrangements can be found in (Kirsten, 1999), (Ramadan, et al., 2003),(Johnston, 2003), (Silvana, 2007)(Pedro, 2008).

5.5.3 Fiscal System Model Description

PSCs are gaining a lot of popularity since it was first introduced in Indonesia in 1966. According to Johnston (2003), more than half of the countries with petroleum potential have a PSC-based fiscal system. The vast majority of the remaining half is based on the traditional concessionary system. TERM-EOR incorporates both types of fiscal systems. However, there are many PSCs that are identical to concessionary system in all but the issue of ownership and the terminology used. It was therefore necessary to incorporate this flexibility into TERM-EOR.

Figures 5-2 & 5-3 depict the typical revenue distributions under PSC and concessionary systems when one barrel of oil is sold at $50. It is worth noting here that the term royalty has been intentionally used in the PSC system flow diagram, as shown in Figure 5-3. There purpose is show illustrate that typical concessionary term such as royalty can be used in PSCs while still resulting the same oil company and government gross revenues, net cash flows, and profit take under different fiscal systems. Some of the terms that are used in the fiscal module are described below.

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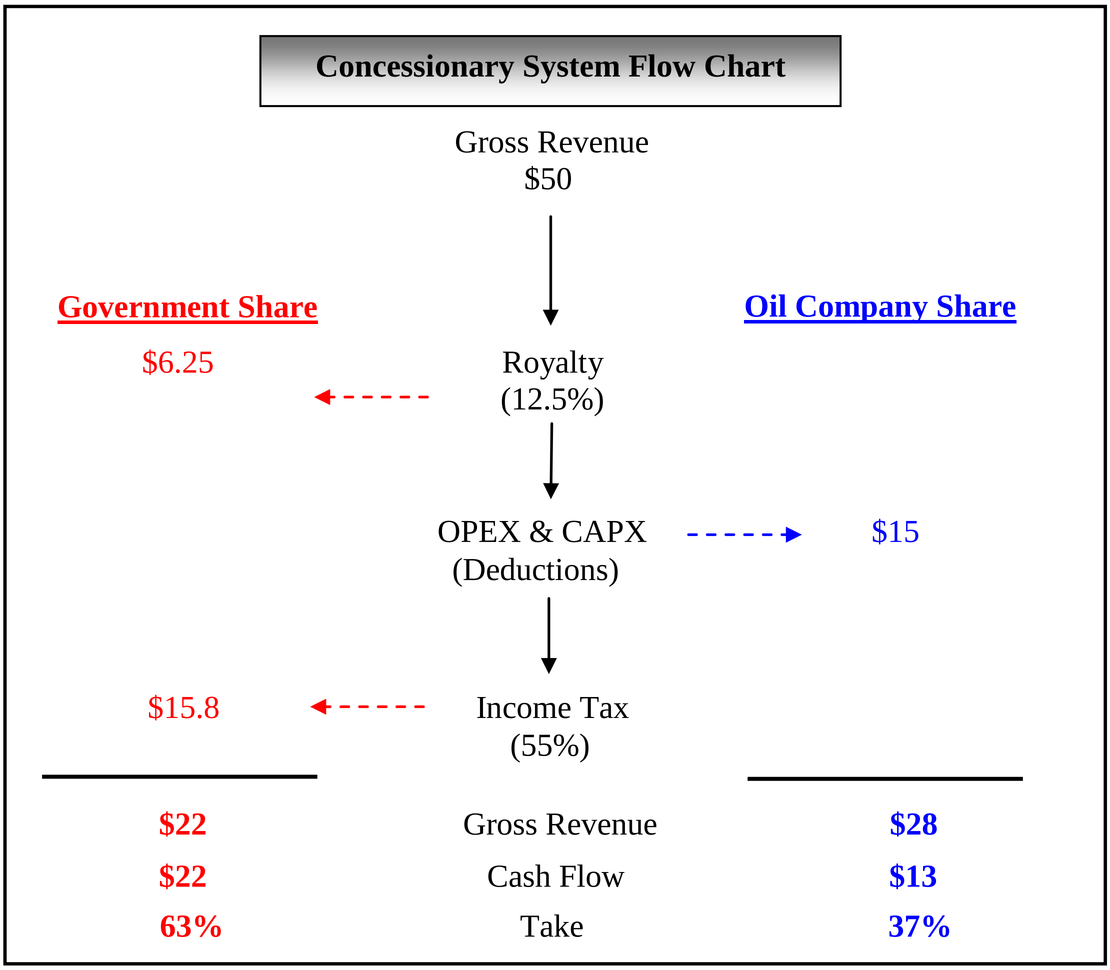


Figure 5-2: Concessionary system flow chart

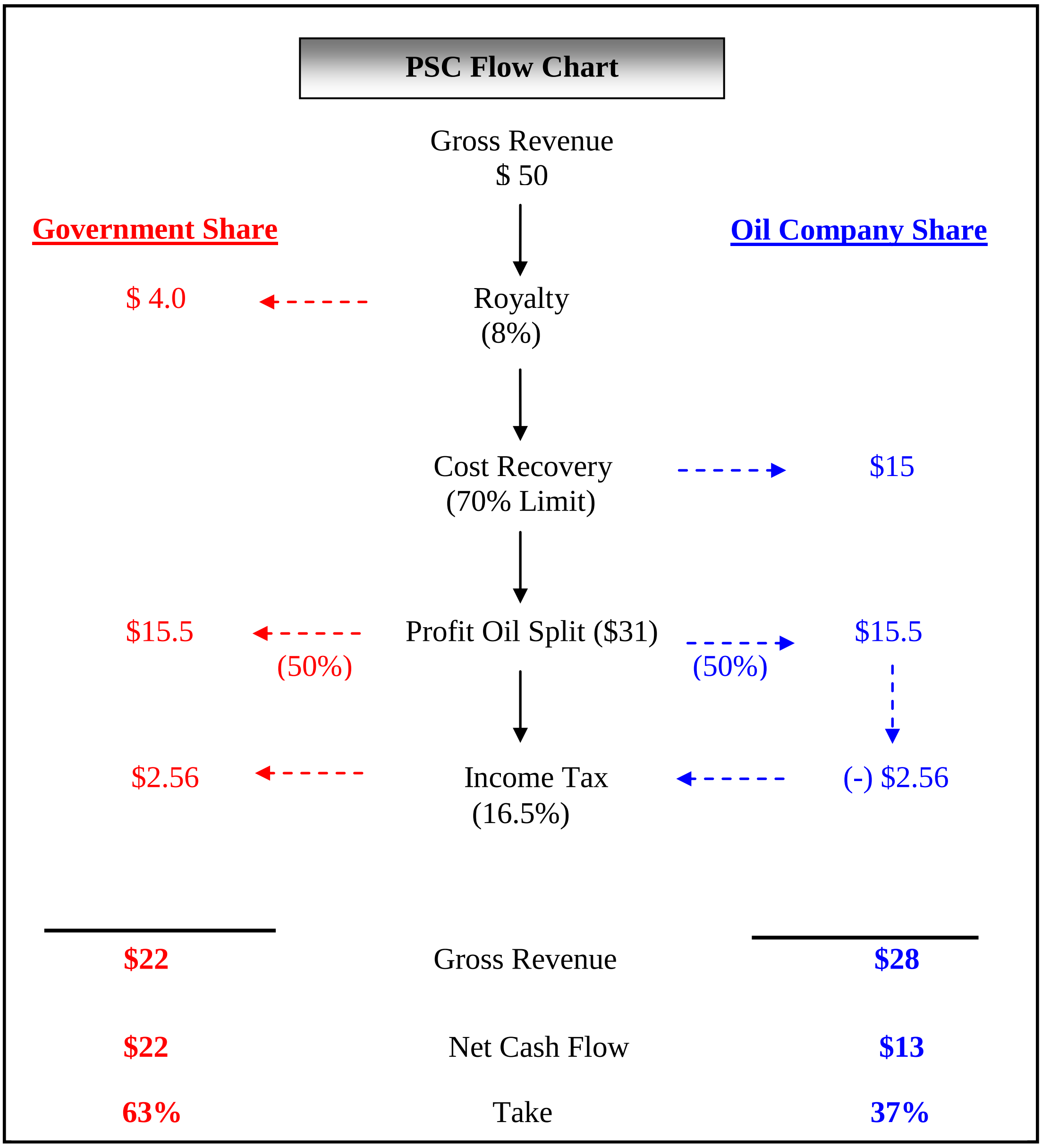


Figure 5-3: PSC system flow chart

5.6 Risk Model

The terms uncertainty and risk are never far off in the analysis of an oilfield investment projects, making risk assessment an integral part of the decision-making process. Risk evaluation is particularly important in S-EOR since most such projects are capital-intensive and low profit operations that require favourable economic conditions, such as high oil prices, to survive. EOR development simply carries higher than average geological, engineering, and financial risk. Monte-Carlo simulation is widely used in the oil industry as a technique to quantify risk. This technique is described here.

5.6.1 Monte Carlo Simulations

Monte-Carlo simulation is used to quantify risk by treating uncertain input parameters of a given problem as stochastic variables. In order to simulate all possible outcomes, all valid combinations of these input parameters are tested. A basic assumption underlying the use of Monte-Carlo simulation is that the behaviour of a system can be described by functions and variables. Once these two are known, the Monte-Carlo simulation can proceed by randomly sampling from the set of descriptive variables. The net outcome of this process is to specify the system output as a statistical distribution of probable values.

The steps in a Monte-Carlo simulation are usually:

1. Creating a parametric model
2. Generating a set of random inputs to the model
3. Input the random input to the model and evaluate
4. Repeat 1 to 3, typically 10,000 times or more
5. Process the entire results using a histogram or probability density function (PDF)

Commercial risk analyzers based on Monte-Carol simulation are readily available in the market and can be easily integrated with Excel spreadsheet. This study makes use of a commercial Monte-Carlo simulator called Risk Analyzer. The Risk Analyzer is a Microsoft Excel Add-In[33] that runs Monte Carlo simulation.

[33]By add-ins.com

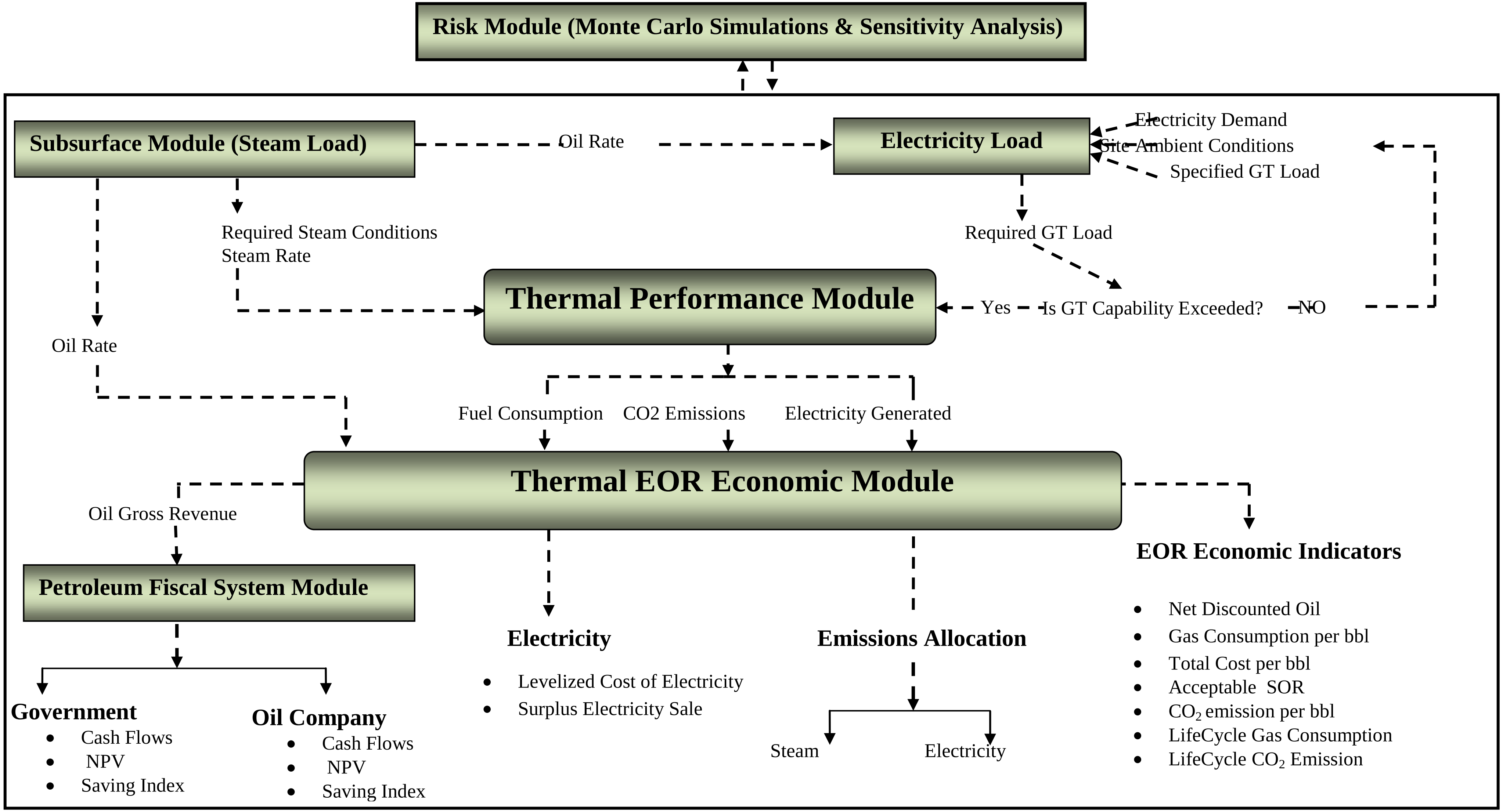


Figure 5-4: TERM-EOR architecture

6 Case Study One: Cogeneration for S-EOR Projects

Unconventional oil developments are energy-intensive pursuits. Large quantities of steam are injected into the reservoir to reduce the oil viscosity and extract it out of the ground. As discussed in Chapters Three and Four, alternative energy sources such as nuclear and solar still face many technical, economic, and regulatory issues that make oil companies reluctant to adopt them. Instead, the oil industry continues to use natural gas as the primary energy source in S-EOR projects while seeking ways to cut natural gas consumption, and thus reduce GHG emissions. This is typically achieved by using cost-effective and technically proven energy efficiency measures such as cogeneration. The inherent reliability and operation flexibility of gas turbine based cogeneration systems make them the ideal choice for the oil and gas industry.

This chapter reports on the thermo-economic and environmental performance of a gas turbine based cogeneration system designed to supply steam for S-EOR project. in addition, opportunities and challenges of adopting this technology in the oil field are discussed.

6.1 Definition

Driven by escalating natural gas prices and tightening environmental regulations, heavy oil developers increasingly recognize the economic and environmental benefits of cogeneration. Cogeneration is defined as the sequential production of useful thermal energy and shaft power from a single energy source. The shaft power can be used to drive electrical generators or mechanical loads such as pumps and compressors. Cogeneration is also often called Combined Heat and Power (CHP). This is because most cogeneration systems are used to provide electricity and process heat. However, the heat energy from electricity production can also be used for other non-heating purposes such as cooling. Therefore, the term cogeneration is more inclusive than CHP and is hence used throughout this study.

The benefit of cogeneration is well known. The total fuel required by cogeneration is less than the total fuel required by two separate systems producing the equivalent amount of power and thermal energy. This is because the heat that would otherwise be wasted in the power generation process is recovered and is utilized to provide process heat. The thermal benefit due to gas turbine based cogeneration is illustrated in Figure 6-1. The thermal energy utilization of the cogeneration system is about 80 percent compared to 38 percent for the fossil fired plant designed to provide power alone. The actual fuel saving would depend on the cycle configuration, operating strategy, prime mover used, as well as the operating conditions. The thermal benefit of cogeneration is further illustrated for a steam turbine cycle in Figure 6-2, which indicated that the overall cycle efficiency decreases from 84% (cogeneration) to 35% as process steam delivery is eliminated (power generation only). Other benefits of cogeneration include lower overall GHG emissions. In addition, cogeneration provides a reliable on-site power generation that is resilient in the event of grid outages. This is particularly important in oil fields where production deferment due to power outage should be avoided at all costs.

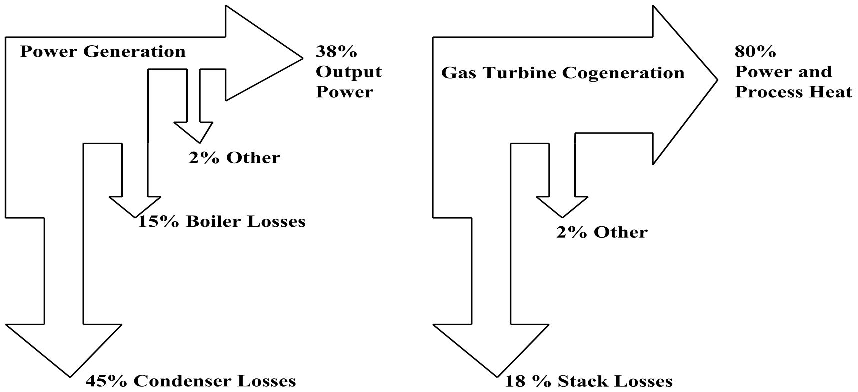


Figure 6-1: Fuel utilization effectiveness

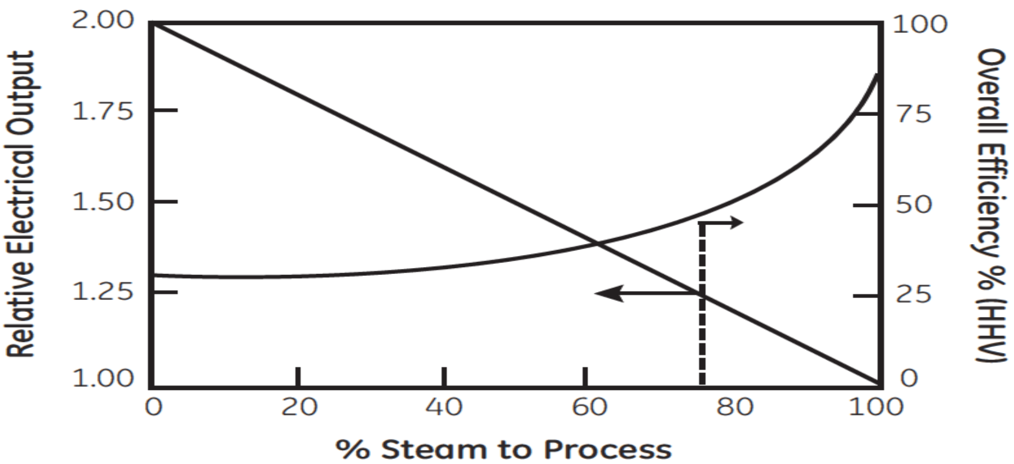


Figure 6-2: Steam turbine cycle performance at various steam demand (John, et al., 2009)

6.2 Cogeneration for S-EOR Projects

6.2.1 Overview

Oil companies have the option of building their own steam plants and purchasing power from the grid, or alternatively, cogenerating steam and power in a single facility. An increasing number of unconventional oil developers are opting for the latter option to cut natural gas consumption and to promote self-sufficiency. In 1998, the latest year at which data is available, cogeneration was providing nearly half of the total steam demand in California thermal fields, with 2071 MW_e of installed capacity (Stevens, et al., 1999). Cogeneration is also playing an strategic role in the development of the vast Canadian oil sands, with 1383 MW_e of installed cogeneration capacity as in 2005 (Nicole, et al., 2005) and an anticipated growth to 3845 MW_e by the year 2019 (OSDG, 2010). In 1998 Indonesia decided to build a large gas-fired cogeneration plant to supply up to 300 MW_e as well as steam to the Duri steamflood project (Chevron, 2010). Oman is another country where cogeneration is being rapidly adopted to power its newly proposed S-EOR projects (Terres, et al., 2009), with an estimated installed capacity of 518 MW_e and further 252 MW_e of planned capacity.

6.2.2 Potential Cogeneration Systems for S-EOR

The primary objective of cogeneration is to supply the energy loads (steam and electricity) required by the oil recovery process. Once the field energy loads are known, the next step is to select an appropriate cogeneration system for the process. Selecting a cogeneration system, however, can be quite complex as there is a large number of steam technologies and plant configurations that can ultimately meet the desired energy loads.

Various technical and economic criteria have been proposed to aid the decision-making process. One of the most widely used technical criteria is the process heat to power ratio (HPR). HPR simply represents the relative thermal load to the power load of the considered process. The process HPR is then screened against the HPR of various cogeneration technologies and plant configurations. In this case, technologies and plant configurations that have the potential to supply the process energy loads are shortlisted for further considerations.

To illustrate the expected range of HPR in S-EOR operations, consider the field described in Table 3-1 in Chapter Three. This field requires 459 MW_{th} of installed thermal capacity and only 13.8MW_e of electrical load (based on 11 kWh/bbl), resulting in HPR of about 33. Consider an extreme case whereby the field has lower thermal load (SOR=2) and higher electrical load (i.e. 20 kWh/bbl), the field would still require 306 MW_{th} and 25 MW_e, resulting in HPR of 12. It is therefore clear that although S-EOR processes are heat-intensive, they consume relatively little electrical energy.

The thermal characteristics of common cogeneration technologies available today are listed in Table 6-1 (Nicole, et al., 2005). It can be readily seen that the range of HPR required by S-EOR projects is generally incompatible with most standard cogeneration schemes. Therefore, tailoring the cogeneration facility to meet one form of energy is very likely to result in a significant surplus or shortfall in the other form, as will be demonstrated later.

Consideration must also be given to the steam conditions required by the oil field. As discussed in Chapter Two, the ranges of steam pressure and steam quality required by S-EOR projects vary considerably from reservoir to reservoir[34]. The selected cogeneration system must therefore be capable of providing the field required steam conditions.

Table 6-1: Performance characteristics of common cogeneration technologies

Cogeneration System	Electrical Efficiency (%)	Overall Efficiency (%)	Heat-to-Power Ratio
Back-Pressure Steam Turbine	12-28	84-92	4.0-14.3
Condensing Steam Turbine	22-40	60-80	2.0-10.0
Gas Turbine	24-42	70-85	1.3-2.0
Combined Cycle	34-55	69-83	1.0-1.7

[34] Steam injection pressure of up to 172 bar is used in some oil fields while the required steam quality typically ranges from 60 to 100 percent.

6.2.3 Steam Turbine Systems (Rankine Cycle)

According to Table 6-1, the most suitable cogeneration schemes for S-EOR projects are steam turbine systems, which are capable of providing the highest HPR. A simplified schematic of steam turbine cogeneration system is shown in Figure 6-3. In this case, a steam generator delivers high pressure steam that is expanded through a steam turbine to generate mechanical energy. Steam required for field injection can either be extracted from intermediate stages within the steam turbine (condensing system) or from the discharge of the steam turbine (non-condensing system).

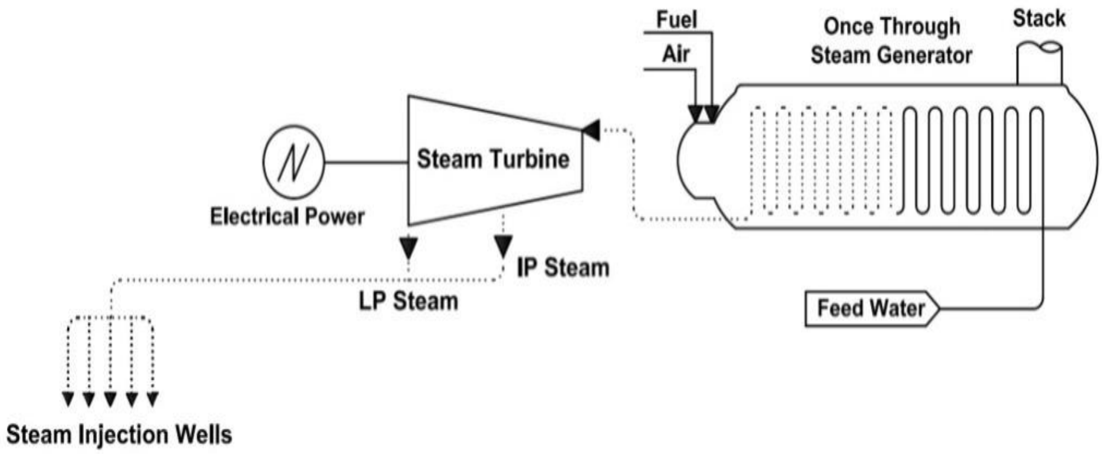


Figure 6-3: Steam turbine cogeneration system

Steam turbines, however, are seldom used in S-EOR operations. The performance of the steam turbine is greatly influence by the quantity and the conditions of the extracted steam. Steam turbines do not operate efficiently with high back-pressure and their performance deteriorates significantly as the extracted steam pressure increases. The efficiency and the power output decrease as the difference between turbine inlet pressure and the process pressure demand becomes smaller, see Figure 6-4. This limits back pressure steam turbines to industrial processes where there is a need for low or medium pressure steam. For oil field application, steam turbine cogeneration can only be used in fields where relatively low injection pressures are required (Rodden, et al., 1981) (Berry, et al., 1995).

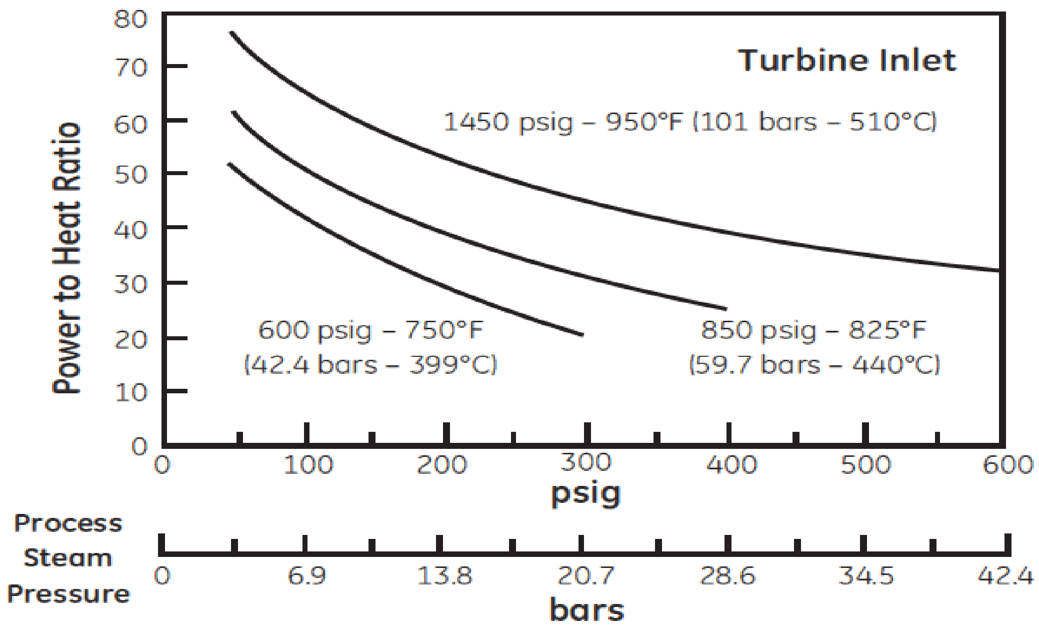


Figure 6-4: Typical performance of Steam turbine cogeneration (John, et al., 2009)

Further complications arise due to the fact that, for optimum and reliable operations, steam turbines require superheated steam. As discussed in section 2.6, high quality feedwater is needed for the generation of superheated steam, requiring significantly more complicated and costly water treatment systems that can handle water produced by the field. Although there is a lack of information on the economic viability of such option, the very limited steam turbine installations in S-EOR operations could only suggest that this option remains expensive.

6.2.4 Combined Cycle Systems

Combined cycle systems use combinations of gas turbines and steam turbines to produce electricity, see Figure 6-5. These systems are configured to produce more power i.e. power generation is prioritized and thus more steam is used in the steam turbine at the expense of less steam being available for process application. These types of plants are mainly used in processes with relatively low steam loads and where electricity sale is the main source of revenue. This is clearly not the case in S-EOR projects. In addition, the existence of a steam turbine in combined cycle configurations implies that the limitations discussed in section 6.2.3 apply here.

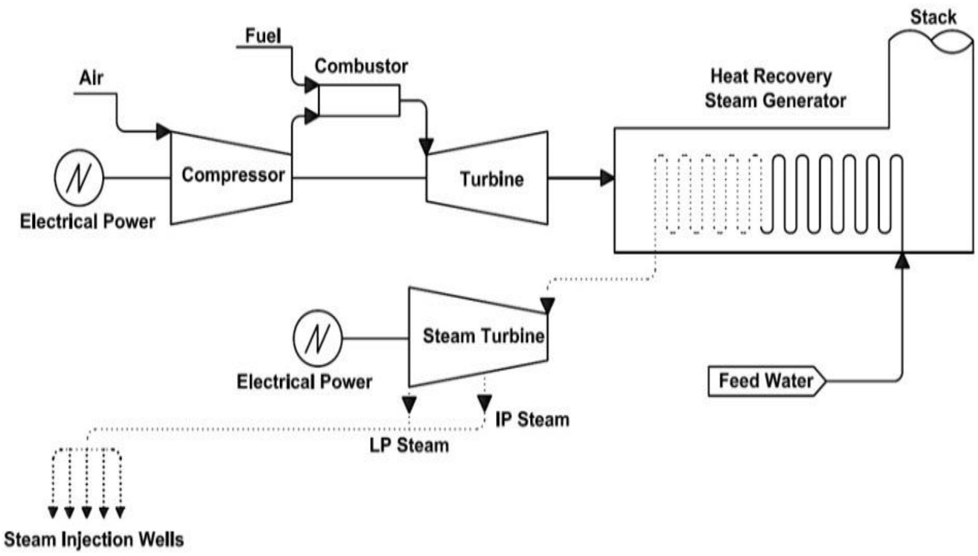


Figure 6-5: Combined cycle system

6.2.5 Gas Turbine System (Bryton Cycle)

The vast majority of installed cogeneration capacity in S-EOR projects worldwide is gas turbine based. The drawbacks of steam turbine cycles in regards to S-EOR operations give a definite advantage to gas turbines. Gas turbine systems can achieve injection pressures as high as required by the reservoir while still maintaining the 80% steam quality limit imposed by oil field operations.

Gas turbine systems in S-EOR projects typically include gas turbine coupled to an electrical generator, which produces electricity and the exhaust heat from the gas turbine is directed to a once through type heat recovery system OT-HRSG, see Figure 6-6. The steam from the OT-HRSG is directed to the oil field for injection. By capturing the waste heat of the gas turbine and putting it to work, the overall thermal efficiency of the plant is increased. The resultant system provides up to 85% utilization of thermal energy input compared to about 35% for a fossil-fuelled gas turbine designed to provide power only.

The main drawback of gas turbine systems in regards to S-EOR operation is their relatively low heat-to-power ratio; refer to Table 6-1. This issue is partially offset by the ability to burn additional fuel in the gas turbine exhaust, which typically contains up to 15% oxygen, to raise the gas temperature before entering the OT-HRSG. This process is commonly known as supplementary firing or duct firing. Depending on the level of firing and the gas turbine exhaust properties, supplementary firing can boost steam production by a factor of two, resulting in higher HPRs. Supplementary firing will result in about 10% to 20% fuel saving compared to conventional boilers to provide the same incremental increase in steam production (John, et al., 2009). The incremental steam production from supplementary firing above that of an unfired case will, characteristically, be achieved at 100% LHV efficiency. This high conversion efficiency is due to the fact that the stack temperature could be unchanged (or even lowered) and the stack mass flow is negligibly increased by the mass of supplementary fuel; resulting in no or little additional heat losses from the supplementary firing system. In addition, gas turbine exhaust simply represents a preheated combustion air that requires less fuel to reach the desired post-combustion temperature.

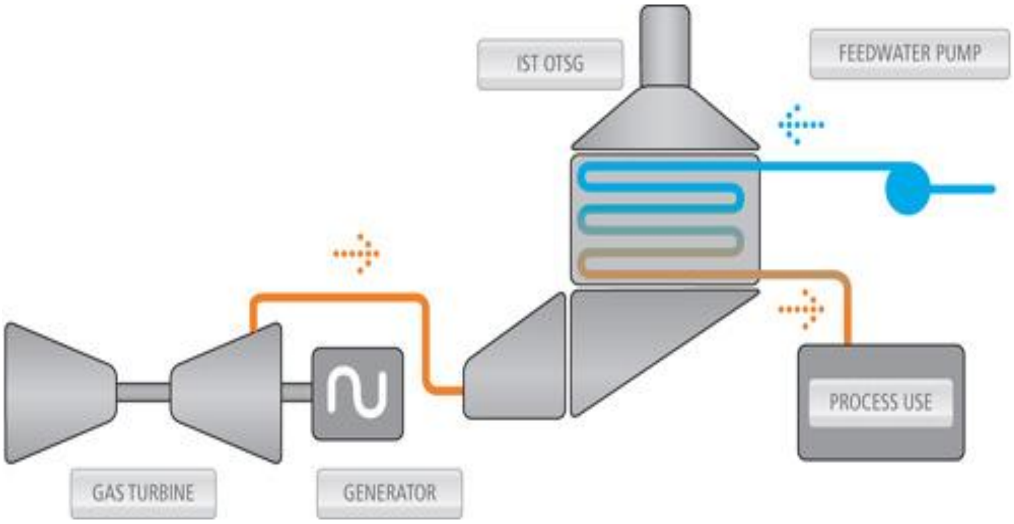


Figure 6-6: Typical gas turbine cogeneration arrangement *(Courtesy of IST)*

6.3 Challenges

The possible use of cogeneration for S-EOR is accompanied by a number of technical, economic, regulatory and institutional obstacles. In general, cogeneration is a trade-off between investing in efficient on-site generation versus the potential to rely on possibly lower priced supply of power generated using depreciated assets or potentially oversupplied market.

The Oil Sands Developers Group (OSDG) conducts annual survey of companies operating or planning to operate cogeneration in the Canadian oil sands. In its 2010 report, OSDG indicates that market fundamentals (e.g. will cogeneration be economically viable), security of supply and reliability, GHG emissions and environmental performance, and transmission access are among the most important factors influencing the decision-making process for cogeneration (OSDG, 2010).

The capital cost for cogeneration is typically greater than simply purchasing electricity from the grid and satisfying steam demand through on-site steam generators. Therefore, the economics of the project must be evaluated with and without incorporating cogeneration. This is to ensure that the potential fuel saving due to cogeneration compensates for the additional upfront capital incurred.

Although supplementary firing improves the HPR, it is typically insufficient to meet the large steam loads required by S-EOR projects. Under these circumstances, tailoring the cogeneration facility to one form of energy is likely to result in a significant surplus or shortfall in the other form. In order to illustrate the argument, a typical gas turbine-based cogeneration facility is modelled using Thermoflex process simulator. A schematic of the cogeneration system is shown in Figure 6-7. More details about the design and operation of the plant are given in subsequent sections. The performance of the cogeneration plant is simulated using different gas turbine sizes and for both fired and unfired HRSG. Thermoflex components library constrains extensive database of hundreds of commercial gas turbines readily modelled and validated. Three representative gas turbines have been selected. Simulation results are summarised in Table 6-2. It is worth noting that the steam output shown in Table 6-2 is the net dry steam available for field injection. The amount of wet steam (80% quality in this case) at the exit of HRSG is much higher, though.

The thermal performance of the three gas turbines is simulated and is then compared to the requirements of Field-A described in Chapter Three in Table 3-1. The first gas turbine is the Hitachi H15. This gas turbine is selected because its power output matches the field power demand (13.8 MW_e) i.e. thermally-following systems. It can been seen from Table 6-2 that sizing the gas turbine to meet the field power demand would result in a very small fraction of the total required steam being cogenerated. In this case, only

5% and 9.5% of the required steam is cogenerated for the unfired and fired HRSG, respectively. Maximum Supplementary firing of 880 °C is assumed in the simulations. It can also be seen that steam production increased by almost a factor of two as a result of supplementary firing, but with additional 1.85 MMcf of natural gas being consumed. Shortfall in steam supply, beyond supplementary firing, is typically provided by additional gas-fired boilers; at the expenses of more fuel being burned and hence lower steam generation efficiency.

According to Table 6-2, if the field full demand of 90,000 bspd is to be cogenerated then there are two options. The first is to use a single Siemens SGT5-2000E but supplementary fired to 880 °C. Although operating at this mode satisfies the field full steam demand, it results in almost 160 MW_e of power being produced in excess of the field requirement i.e. 40 kWh of excess power per barrel of steam produced. Furthermore, 20.1 MMcf of natural gas is consumed in the supplementary firing. The second option is to use two Siemens SGT5-2000E in parallel. This option provides the full steam load while eliminating the need for supplementary firing. This operating strategy, however, results in 315.5 MW_e of excess power being produced (84 kWh of excess electricity per barrel of steam).

It is evident that tailoring the cogeneration facility to meet the field steam demand is likely to result in a great deal of power being produced, much more than would be needed by the S-EOR project. In this case, excess power can either be used to support other nearby oil production activities or be exported for sale. In the latter, cogenerators will have to secure access to the grid and find a fair market for their surplus electricity. In many countries, however, regulatory as well as economic constraints have kept access to the national grid almost entirely within the domain of the electric utility companies. Utility companies have traditionally been concerned about competition from cogenerators, believing that demand for their electric power is somewhat reduced by cogeneration. Limited access to the grid has historically been a major obstacle to the energy savings that might otherwise be achieved through cogeneration. Government intervention, through proper legislations, that encourage cogeneration is required in this case. One of the few countries that have realized the need for such legislations is the U.S. The U.S. government approved a federal legislation known as the Public Utilities

Regulatory Policies Act of 1978 (PURPA) which mandates electric utilities to purchase power from and sell power to qualifying cogenerators. The PURPA 1978 also establishes a basis for paying cogenerators a fair price for power sold to the utility companies. The effect of this rule on the economics of cogeneration in the U.S has been dramatic. Other incentives such as investment tax credit can also be used to encourage cogeneration. Unfortunately, not all countries have PURPA-like legislations and therefore oil companies are faced with the choice between contending against large and well-diversified utility companies or simply size their cogeneration facilities to meet the on-site power demand. Some large oil companies operate their own power grid. In this case, power generation plants may be relocated closer to S-EOR activities and the excess power is exported through the companies' grid to serve other oil fields.

Another regulatory setback is the fear among oil companies of being regulated as a utility as a consequence of connecting to the national grid. Oil companies have concern that they may have to go through the same stringent approval schemes required for large central power station.

The lack of clarity on future GHG emissions regulation and compliance obligations presents a major obstacle to potential large scale users of cogeneration. Although cogeneration reduces *overall* GHG emissions associated with the facilities heat and electricity consumption, by generating electricity and heat onsite, cogeneration can increase the *on-site* GHG emissions. Environmental regulations do not always recognize this overall emissions reduction benefit but rather accounts for the total GHG emissions. In this case, cogenerators could be discouraged from installing cogeneration systems even if they could improve environmental performance due to higher environmental compliance costs. Researcher, government agencies and companies have also struggle with the question of how to allocate emissions among the various energy products from cogeneration. A number of methods have been proposed but their inconsistency or overlay complexity have prevented them from being universally accepted (Rosen, 2006)(Doluweera, et al., 2010)(Remei, et al., 2011).

Table 6-2: Power and steam output from various commercial gas turbines

Parameter	Gas Turbine Model		
	Hitachi H15	GE GE9171E	Siemens SGT5-2000E
Rated Power Output, (MW)	13.86	127.5	164.7
Steam Rate (bspd) (unfired HRSG)	4500	35700	45100
Steam Rate (bspd) (Fired HRSG, 880 °C)	8550	71600	90000
Steam Deficit (bspd) (unfired HRSG)	85500	54300	44900
Steam Deficit (bspd) (Fired HRSG, 880 °C)	81850	18400	-
Excess Electricity (MW)	-	113.7	150.9

6.4 Cogeneration Evaluation

In order to quantify some of the incentives and obstacles discussed earlier, TERM-EOR is used in this case study to evaluate a typical S-EOR project with and without incorporated cogeneration. Supply costs, project feasibility, CO_2 emissions, and other economic and environmental indicators are compared under the two development scenarios.

6.4.1 Steam and Oil Profiles

As discussed in section 5.2.3, TERM-EOR has the flexibility to make use of user-defined field inputs obtained from actual field data or predicted using commercial reservoir simulators. This case study utilizes scaled steam and oil profiles predicted using commercial reservoir simulators of steam injection project already under development. The field steam and oil profiles are shown in Figure 6-7[35].

[35]For confidentiality purposes, the data in Figure 7-7 has been normalized

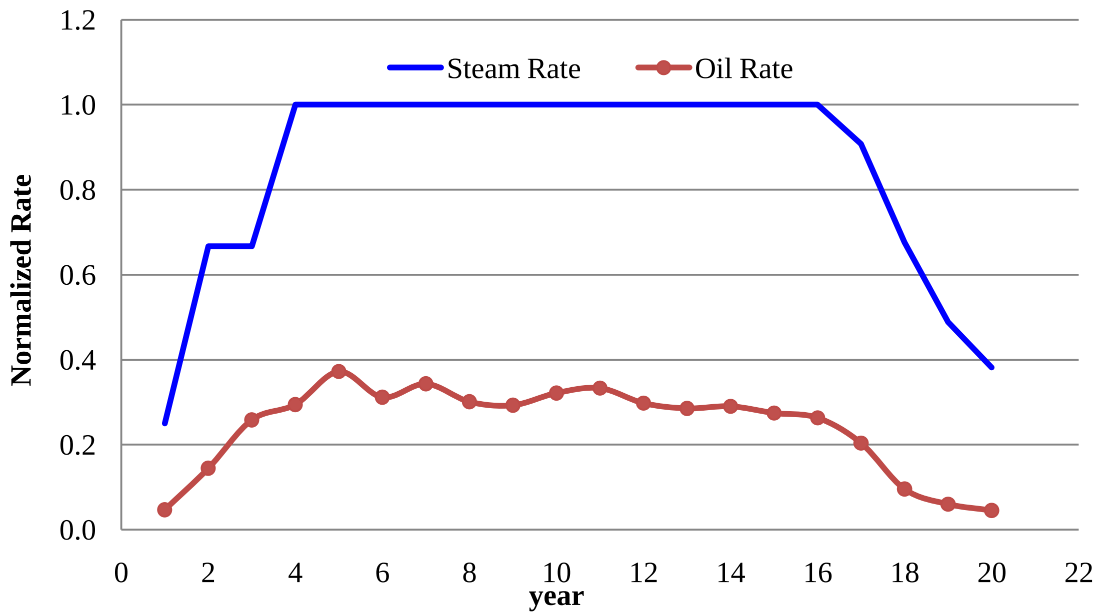


Figure 6-7: Field steam load and oil rate

6.4.2 Cogeneration Plant Description

For consistency, the steam plant used in this case study is identical to the one described in section 3.2.1 but with the fired boilers being replaced with a HRSG system coupled to an industrial gas turbine. A schematic of the cogeneration plant is shown in Figure 6-10. The gas turbine produces the required power while exhaust gases are diverted into a HRSG to generate dry steam for field injection.

The cogeneration plant is controlled to meet the field steam demand by first utilizing the GT exhaust gases (unfired HRSG). If the energy from the GT exhaust is inadequate to cogenerate all the required steam, supplementary firing (up to 880 °C) is used. If, however, the permissible firing temperature is reached before the field's full steam requirement is met, fired boilers are brought on-line to supplement steam production. This control strategy ensures that the field steam requirement is always satisfied regardless of the GT load and operating conditions.

6.4.3 Gas Turbine Modelling and Control

The performance of gas turbine cogeneration plants is influenced by a number of factors including the GT load, ambient conditions, and control strategy. The maximum cycle efficiency is generally achieved when the GT is operated at its ambient capability. It is very rare, however, for the plant to operate exactly at the design conditions and at full load. At off-design operations such as the reduction of GT load or/and changes in ambient conditions, the cycle performance can fall off rapidly as the GT exhaust properties deteriorate, and thus negatively affecting the HRSG performance.

Reduction in GT output can be achieved using two main techniques (Dechamps, 2010):

- Fuel flow control: fuel flow to the GT combustor is reduced which results in lower turbine inlet temperature (TIT) and hence reduced GT output. This control strategy is referred hereafter as TIT-Control.
- Engine mass flow control: the air flow to the compressor is reduced by changing the angle of the variable geometry inlet guide vanes (VIGV) at the inlet of the compressor. In this case, the TIT is maintained constant and the VIGV is gradually closed until the mass flow is reduced to 75-83% of the design mass flow. Further reduction in GT load is achieved by reducing the TIT with the VIGV in the fully closed position i.e. with the air mass flow at 75-83% of the design value, depending on the engine design.

The majority of Thermoflex gas turbine models are based on physical parameters which are reverse-engineered from available data for the commercial engines. These models are built to reflect the commercially available off-the-shelf engines and they are quite flexible and responsive to changes in operating conditions. However, these built-in models have limited flexibility in regards to GT control strategy. In order to evaluate the performance of the cogeneration plant under different GT control strategies, it was necessary to use the various components available in Thermoflex library to model gas turbine cycle. This include air intake, compressor, combustor, cooled turbine, and exhaust system. The model represents a commercially available single-shaft heavy-duty gas turbine. The GT rated performance is shown in Table 6-3.

A simplified schematic of the modelled GT is shown in Figure 6-8. Both Thermoflex physical-based model as well as Original Engine Manufacturer (OEM) data is available to validate the GT model at design and off-design. The OEM data is available in the form of exhaust gas properties (mass flow and temperature) versus GT load at different ambient conditions. This is a very useful data since it allows the performance of the engine to be validated at off-design conditions. At design conditions, the model perfectly matched the expected performance after a few number iterations. At off-design, however, the model required extensive tuning to match the expected off-design performance. This has been primarily achieved by manipulating the quantity and location of turbine cooling air which is extracted at different ports along the compressor.

Table 6-3: GT rated performance

Parameter	Unit	Value
GT Rated Power	MW	125.7
Pressure Ratio	-	12.4
Inlet Mass Flow	kg/s	1124
Firing Temperature	°C	410
Exhaust Temperature	°C	541

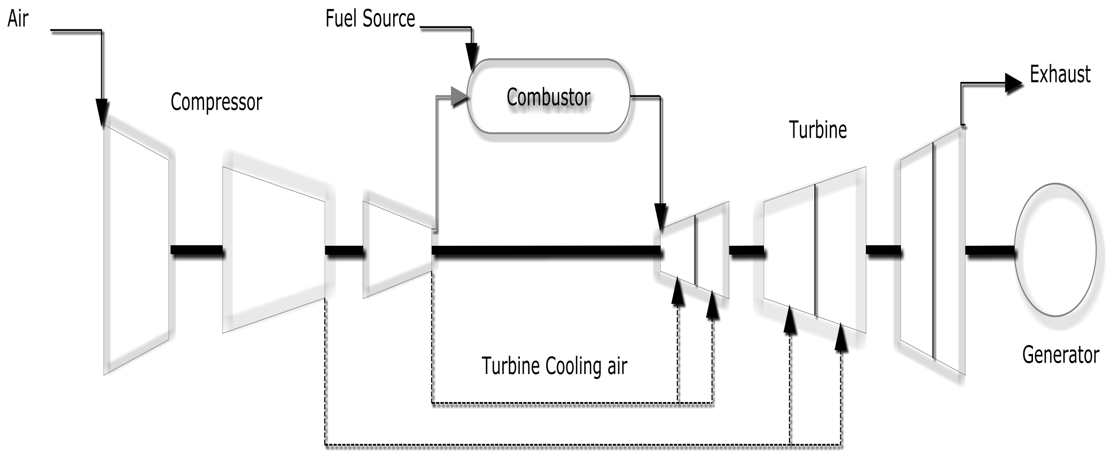


Figure 6-8: Schematic of the gas turbine detailed model

6.4.4 Turbine Blade Cooling Modelling

Turbine blades are responsible for extracting energy from the high-temperature, high-pressure gas produced by the combustor and therefore they are often the life-limiting component of gas turbines. Furthermore, the GT thermal efficiency is a strong function of pressure ratio and to a lesser extent of the TIT. The latter is limited by the materials of hot gas path (HGP) components such as the turbine nozzle guide vanes (NGV) and turbine blade. Turbine blades are often manufactured from exotic materials such as superalloys which can withstand elevated temperatures. Improvements in metallurgy and turbine cooling technologies have allowed modern gas turbines to operate at much higher TIT than was possible five decades ago. In addition, continuous cooling of HGP components allows their operating temperature to exceed the material's melting point without affecting their mechanical integrity (Rolls Royce , 1996).The cooling air is typically bled from various ports along the compressor, as shown in Figure 6-8.

The amount of bleed air influences the performance of the GT, hence the overall efficiency of cogeneration cycle (Tong, et al., 1995). Thermoflex has the capability to model cooled turbine stages (rotor and stator) in great level of details, see Figure 6-9. However, detailed information about the cooling system for the selected GT is not publicly available. This issue is overcome by utilizing the OEM data available for the engine. The idea is to reversed-engineer the necessary turbine cooling parameters such as cooling effectiveness, design metal temperature, cooling leakage by manipulating these parameters until the off-design performance of the model GT approximately matches that of the OEM data.

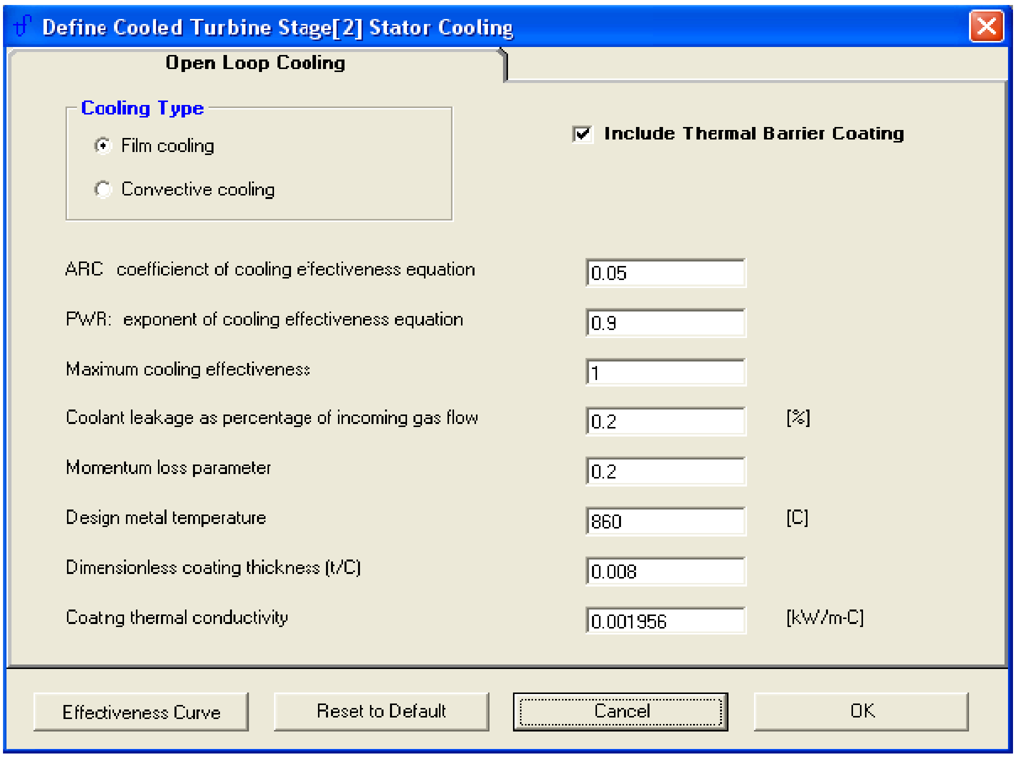


Figure 6-9: Thermoflex turbine cooling input menu

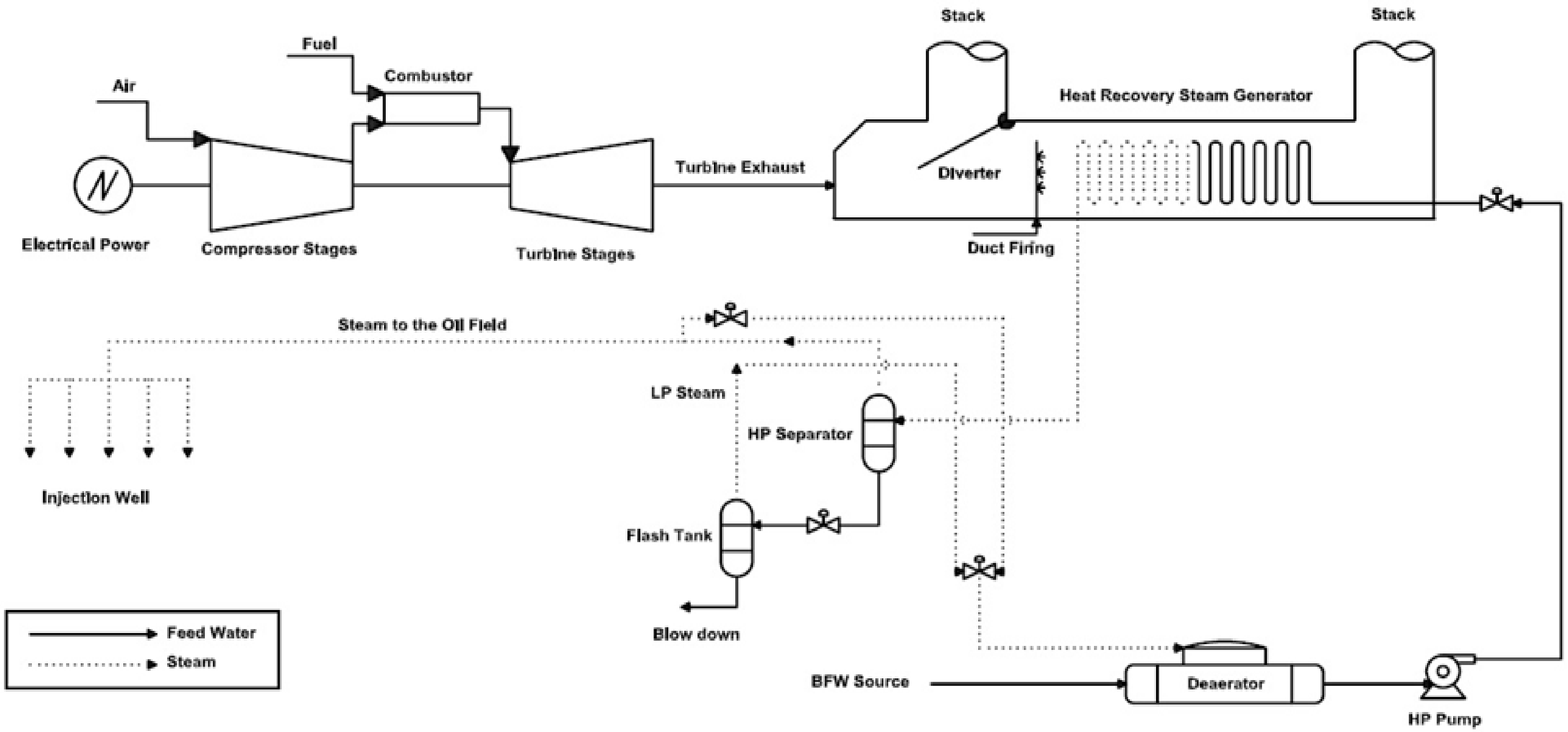


Figure 6-10: Typical oil field cogeneration system

6.5 Cogeneration Thermodynamic Performance

6.5.1 Gas Turbine Performance

Gas turbines are air-breathing engines and thus their performance is changed by anything that affects the density and/or mass flow of the air intake to the compressor. The gas turbine thermal efficiency is a strong function of the cycle pressure ratio; see Equations 6-1 & 6-2. In real cycles, the firing temperature (T_3 in the equations) has also some impact on the simple cycle efficiency, but the main influence is on the useful work of the GT, see Equation 6-3. Exhaust gas temperature, which is important for heat recovery applications, is essentially a result of the pressure ratio and firing temperature. Higher firing temperature will raise the exhaust temperature, whereas higher pressure ratio will tend to depress it.

Equation 6-1

Equation 6-2

Equation 6-3

Where,

UW	Useful work
m	Inlet mass flow
η_c	Compressor isentropic efficiency
η_c	Turbine isentropic efficiency
γ	Ratio of specific heats
C_p	Specific heat of gas at constant pressure
T_1, P_1	Compressor inlet temperature and pressure respectively
T_2, P_2	Compressor outlet temperature and pressure respectively
T_3, P_3	Turbine inlet temperature and pressure respectively
T_4, P_4	Turbine outlet temperature and pressure respectively

The ambient temperature has pronounced influence on the GT performance. An increase in ambient temperature means that less air is drawn into the compressor, reducing the engine power output. In addition, an increase in ambient temperature decreases the compression process efficiency, which is reflected in an increased compression work.

The effect of ambient temperature on the GT inlet mass flow and the compressor discharge pressure is shown in Figure 6-11. A 30 °C increase in ambient temperature above the ISO conditions results in about 14% reduction in inlet mass flow i.e. 0.45% reduction in mass flow for every degree centigrade increase in ambient temperature. Compressor discharge pressure has also dropped by 13% for the same increase in ambient temperature. These two performance parameters are crucial because they affect the GT power output as well as overall thermal efficiency (η).

Figure 6-12 indicates that the GT output is reduced by about 20%; from 125.7 MW_e at 15 °C to 101 MWe at 45 °C i.e. 0.67 percent drop in power output for every degree centigrade increase in ambient temperature. There is also about 2% drop in efficiency as a result of the 30 °C increase in ambient temperature. This may sound insignificant, but the fact that the fuel is single largest operating cost in GT operations makes this drop in efficiency economically significant. As will be demonstrated later, reduction in output power and efficiencies translate into higher power generation costs.

The effects of GT control strategies on exhaust gas temperature and mass flow are shown in Figures 6-13 to 6-16. Figure 6-13 illustrates the reduction in the fuel flow and the TIT as the GT load is reduced using TIT control strategy. For a given ambient temperature, the GT exhaust mass flow remains almost unchanged throughout the operating rang, see Figure 6-14. The exhaust temperature, however, shows significant degradation; driven by the reduction in the cycle pressure ratio. More than 175 °C drop in exhaust temperature is predicted as the GT load is reduced from base-load down to 50%. Lower exhaust temperatures have detrimental impacts on the performance of the HRSG downstream, as will be discussed later.

For recovery applications, where the gas turbine will be operated at less than its ambient capability, there is a thermodynamic advantage in maintaining part load exhaust temperature at the highest possible levels. One way to accomplish this is by modulating the engine mass flow using the VIGVs at the compressor inlet. In this case, the TIT is kept at its design value while the VIGVs are used to modulate the inlet mass flow into the engine. The exhaust characteristics for VIGV control are shown in Figures 6-15 and 6-16.

Figure 6-15 shows the mass flows as a function of the power output for the VIGV control. It can be seen that, at a given ambient temperature, the GT output can be reduced to about 80% of its ambient capability by reducing air flow. Further reduction in output power would require a reduction in the TIT. The higher exhaust temperatures available with VIGV control are readily apparent from Figure 6-16. For example, at 80% GT load on a 15 °C ambient day, the GT would have an exhaust temperature of about 570 °C with VIGV control compared to 472 °C if the GT is operated with TIT control, almost 100 °C gain in exhaust temperature.

Figure 6-17 illustrates the effect of the control strategy on the GT efficiency when the output power is reduced. It is clear that the efficiency drops at part load are larger with the VIGV control. Closing the VIGV produces larger drop in the compressor isentropic efficiency because the HP stages have only a fraction of the mass flow they are designed for (Dechamps, 2010).

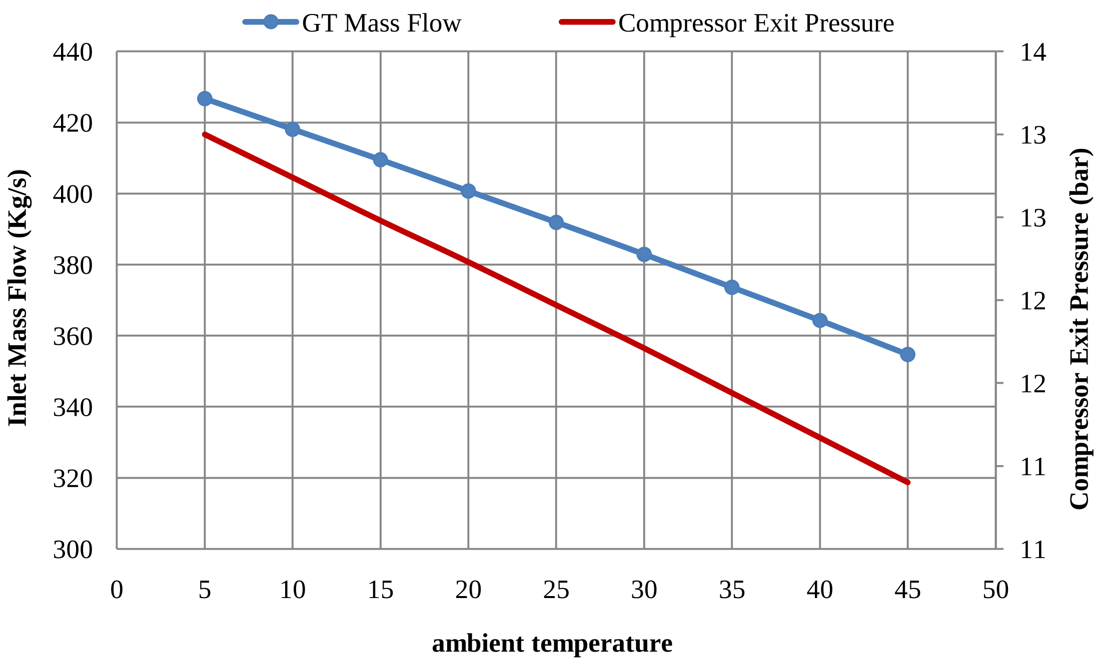


Figure 6-11: Effect of ambient temperature on gas turbine inlet mass flow and pressure

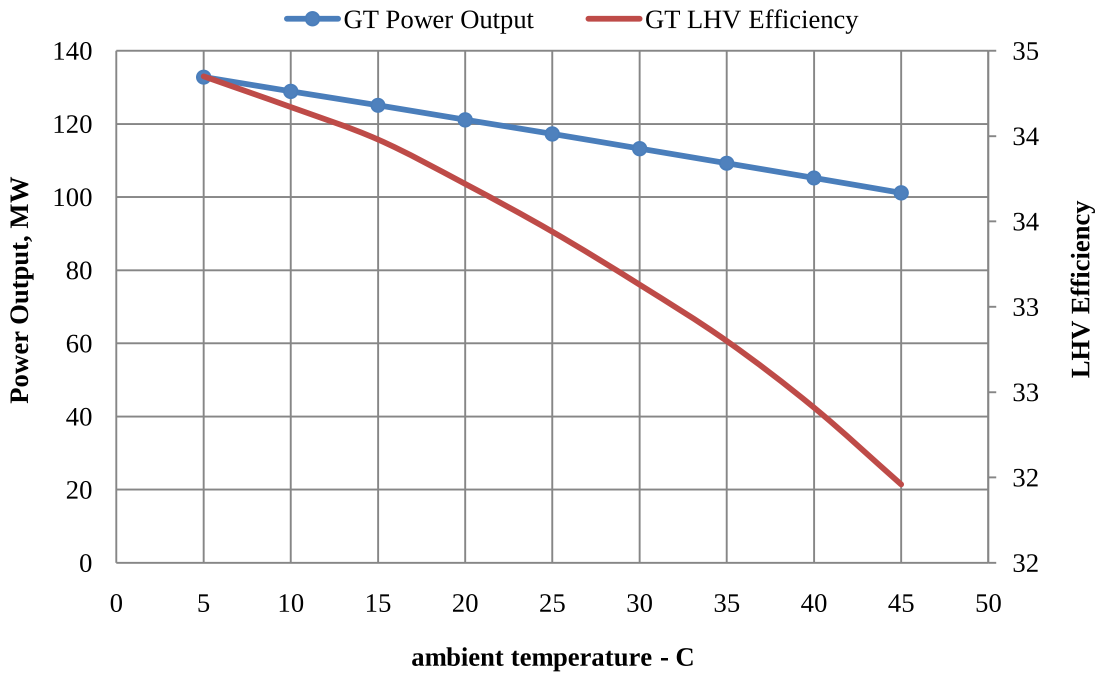


Figure 6-12: Effect of ambient temperature on gas turbine power and efficiency

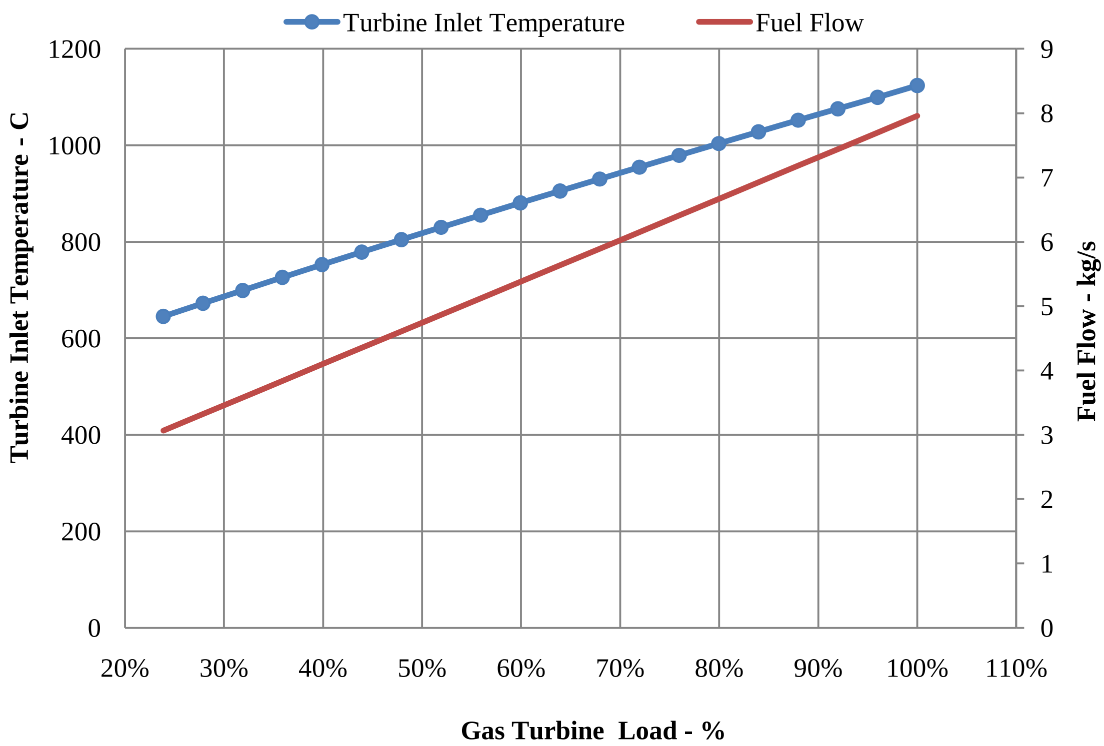


Figure 6-13: Fuel flow & turbine inlet temperature for TIT control

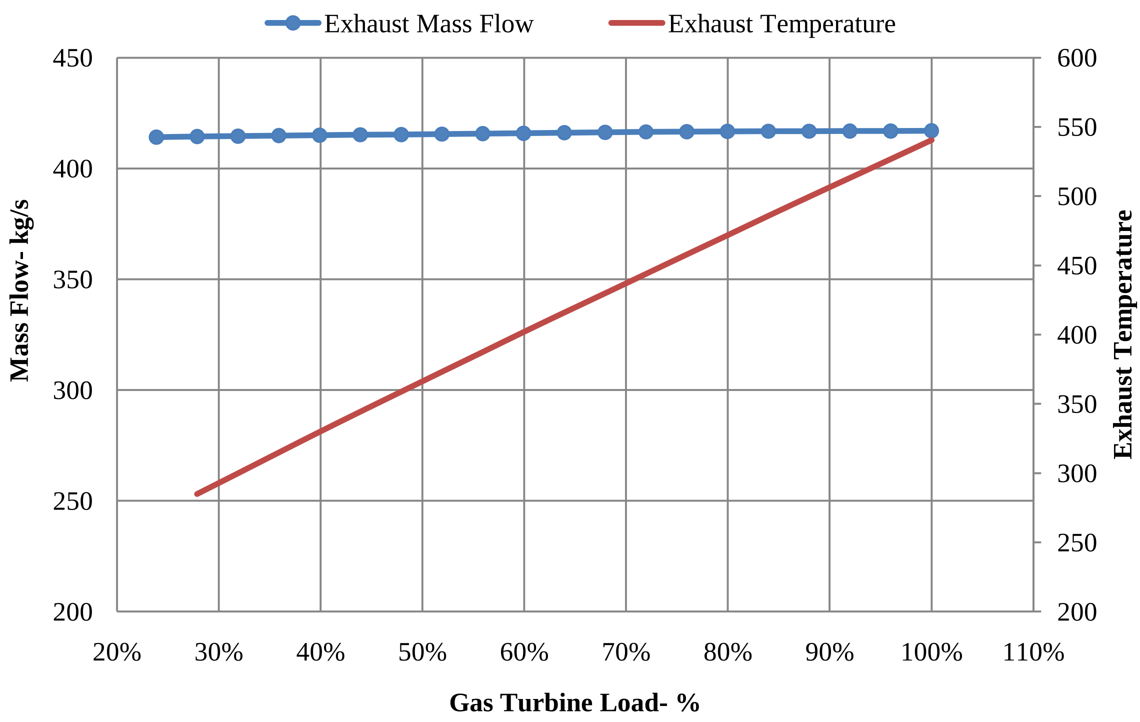


Figure 6-14: Exhaust mass flow & temperature as a function of GT load for TIT control

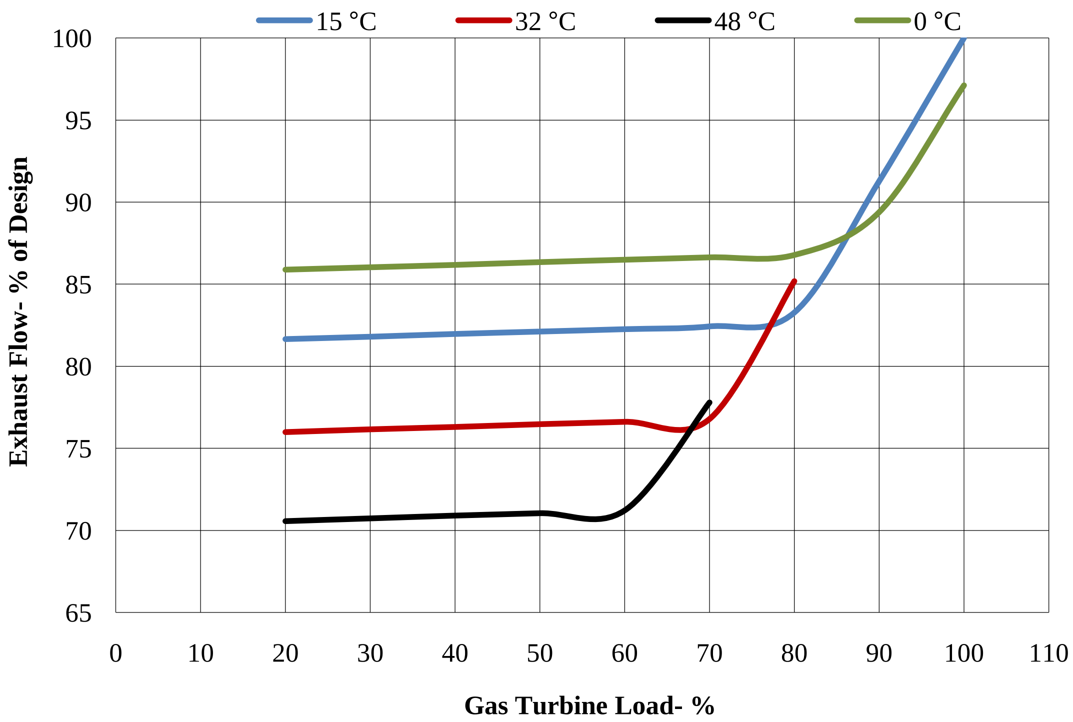


Figure 6-15:Exhaust mass flow as a function of GT load for IGV control

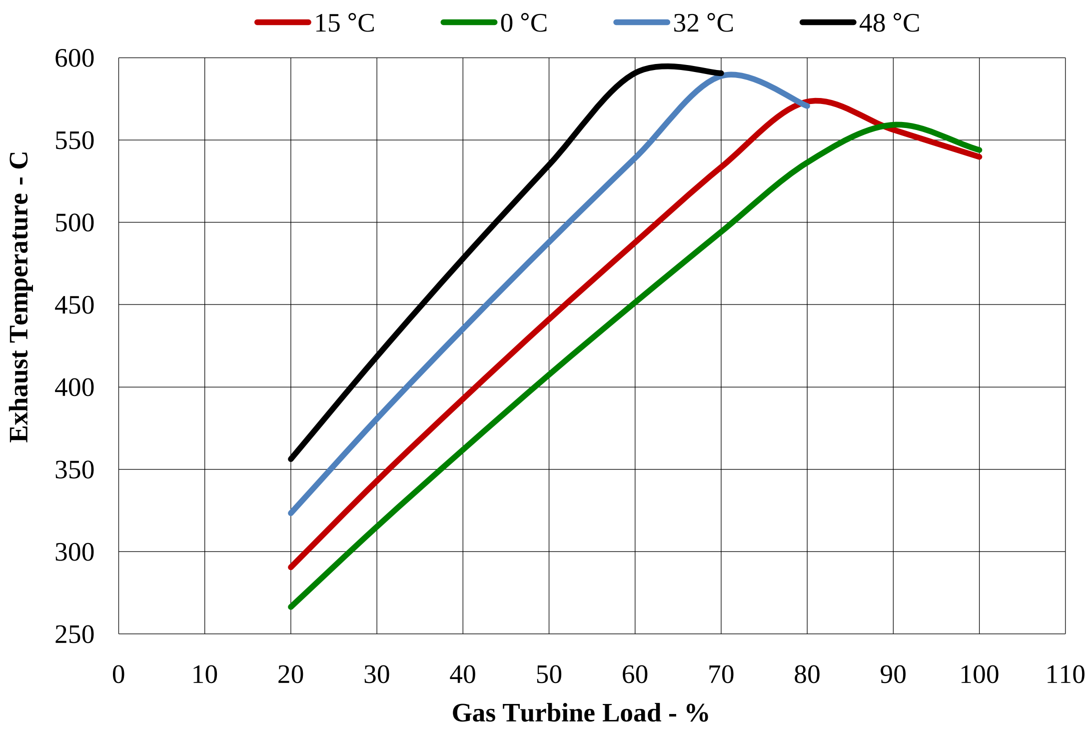


Figure 6-16:Exhaust temperature as a function of GT load for IGV control

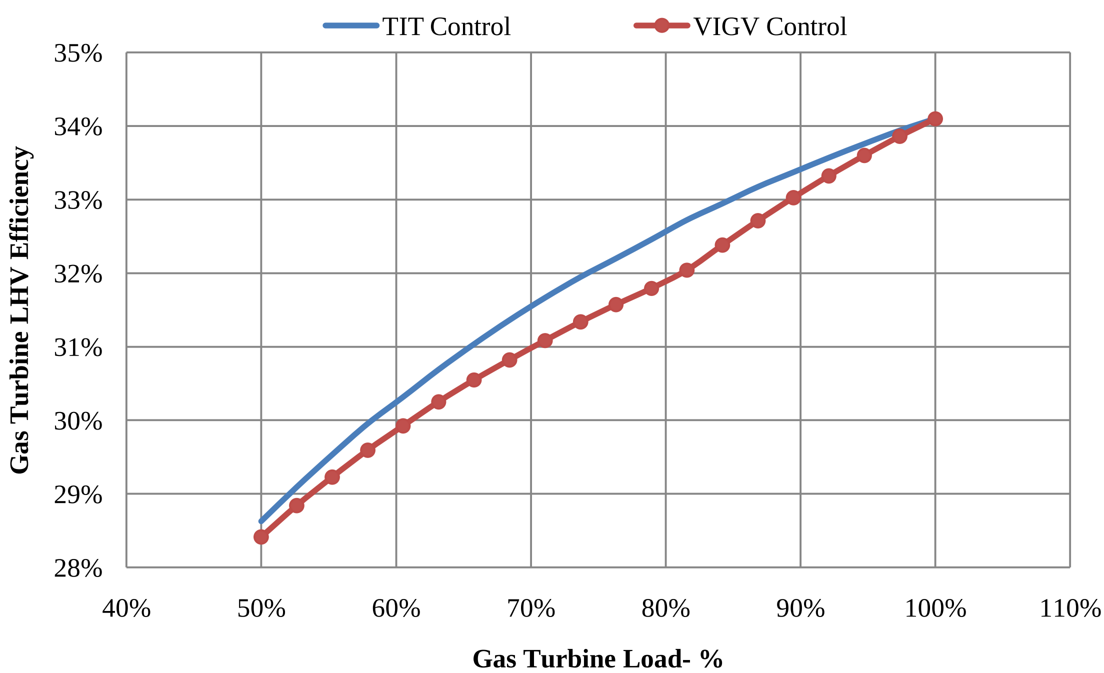


Figure 6-17: Gas turbine efficiency for TIT and VIGV control strategies

6.5.2 HRSG Performance

The performance of cogeneration is strongly related to the GT operation. The heat quantity and quality of the heat available in the exhaust gas will determine the amount of steam that can be cogenerated. Figure 6-18 shows the performance of the cogeneration plant generating 70 barg dry saturated steam using the exhaust of the gas turbine described earlier. More than 3% reduction in steam rate is predicted due to an increase in ambient temperature from 15 to 45 °C. This is mainly attributed to the reduction in the GT exhaust mass flow at higher ambient temperature, as illustrated in Figure 6-11. In S-EOR operations, this implies that less steam is available for field injection; which may negatively impact the oil recovery process. It is worth to note that the results represented in Figure 6-18 are for unfired HRSG. If, however, fired HRSG is used then reduction in steam output can be compensated by increasing the level of supplementary firing to maintain constant steam production. This highlights one of the advantages, in terms of operating flexibility, brought by incorporating supplementary firing. The performance of the cogeneration plant is also evaluated under the two GT control strategies described earlier, for both fired and unfired HRSGs. The results are shown in Figures 6-19 and 6-21. The following observations can be made:

Figure 6-19 shows the performance of the unfired HRSG. The dry saturated steam rates available with and without VIGV control at ambient temperatures of 15 and 45 °C are shown. If the GT is operated at 80% of its ambient capability on a 15 °C ambient day, the steam rate drops by 11% and 25% for the VIGV and TIT controls respectively. In absolute terms, the VIGV control would result in 33500 kg/hr (5055 bspd) additional steam production compared to TIT control. At SOR of 2.5, this is the amount of steam required to produce 2020 bopd.

If the steam production rate is to be maintained at the baseline value of (67.7 kg/s) throughout the operating range of the GT, additional fuel burning would be required to supplement steam productions at lower GT load. Figure 6-20 shows the additional fuel required as a function of the GT load for the two control strategies. Because supplementary firing is more efficient than fired-boilers, it is assumed that the additional steam capacities are provided by firing the GT exhaust (fired HRSG).

The fuel saving benefits of VIGV controls is readily apparent in Figure 6-20. The difference in fuel consumptions between VIGV and TIT controls occurs at about 80% GT load, with the VIGV resulting in 1980 MMBtu lower daily fuel consumption. This is because, the GT exhaust temperature is maximized when the VIGVs are in their fully closed positions at about 80% GT load, refer to Figure 6-16.

The monetary saving if the cogeneration plant is operated with VIGV compared to TIT control is indicated in Figure 6-21. Figure 6-21 shows that at GT load of 80% of site capability, a fuel saving of about 3 and 6 $MM can be obtained at natural gas prices of 4.2 and 8.4 $/MMBtu, respectively. The actual amount would depend of the operating conditions as well as fuel prices.

The thermodynamic superiority of VIGV over TIT control is clear. However, there are some situations in which the use of VIGV control may be unfavourable. Figures 6-22 illustrates the relationship between the GT load and the outlet temperatures of the supplementary firing system. It can be observed that higher firing temperatures are required to compensate for the heat lost due to the reduction in engine mass flow associated with closing VIGVs. In contrast, supplementary firing outlet temperature with TIT control is lower because in this case the engine mass flow remains almost unchanged and supplementary firing is utilized to restore the exhaust temperature dropped due to TIT reduction, refer to Figure 6-14. Therefore, in applications where the maximum allowable level of HRSG firing temperature is limited, this limit is reached faster with VIGV control than TIT control. Furthermore, some unique applications require rapid load pickup capability of the GT such as in isolated generator drive application (Rowen, et al., 1983). Because the exhaust temperature is used as the measured variable in GT control system (Rowen, 1988), the TIT control with its low part-load exhaust temperature profile allows greater allowable fuel increase before being limited by exhaust temperature control. Therefore, the load pickup capability of the GT is greatest when operating in TIT control (constant mass flow) as opposed to VIGV (mass flow reduction), (Rowen, et al., 1983). For this reason, this fact must be considered when choosing a control strategy if rapid power output response is a requirement.

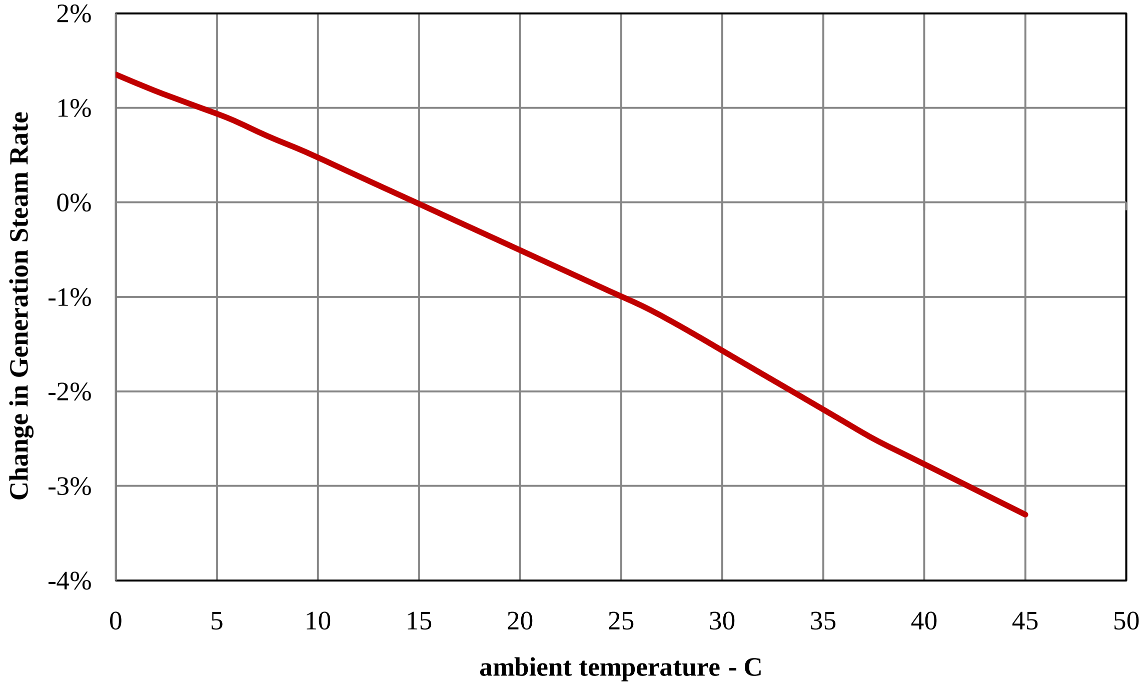


Figure 6-18: Effect of ambient temperature on steam output

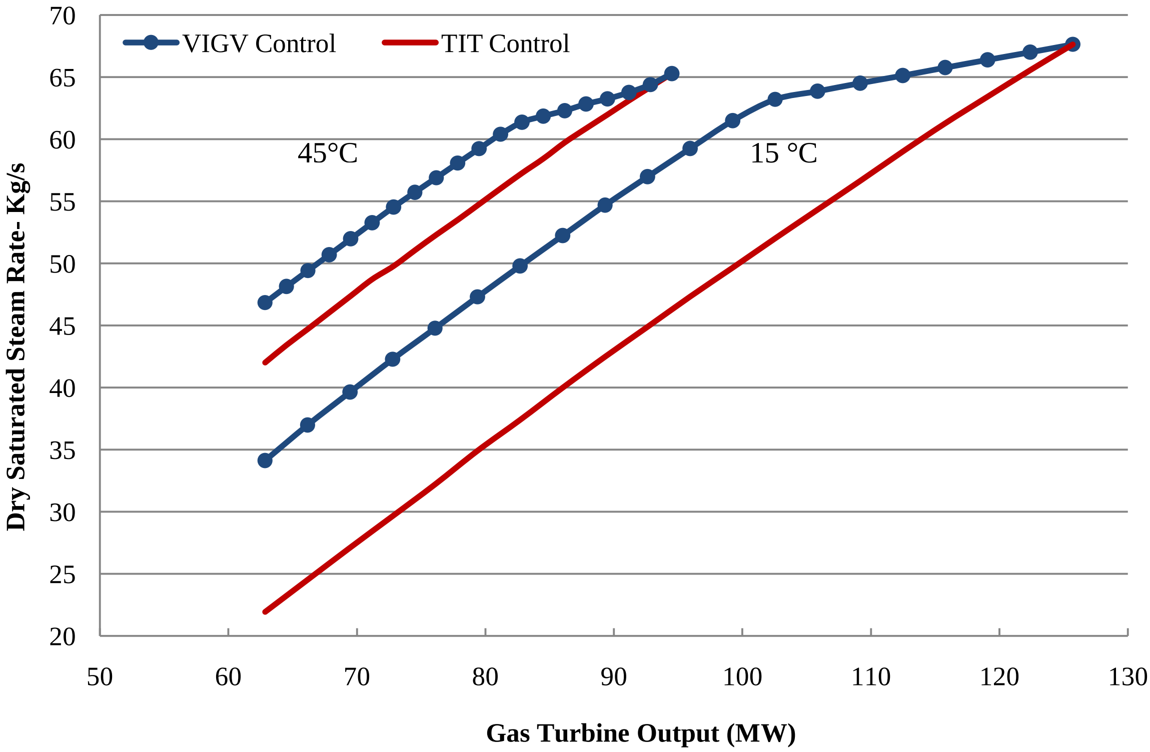


Figure 6-19: Unfired HRSG performance under the two GT control strategies

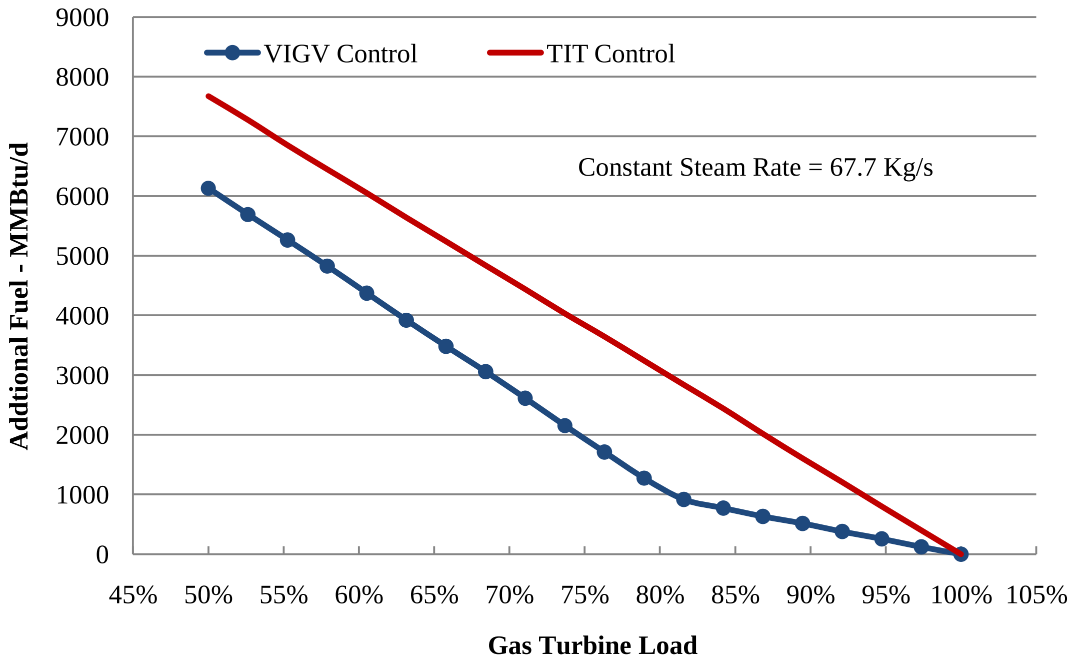


Figure 6-20: Additional supplementary fuel required to maintain constant steam rate

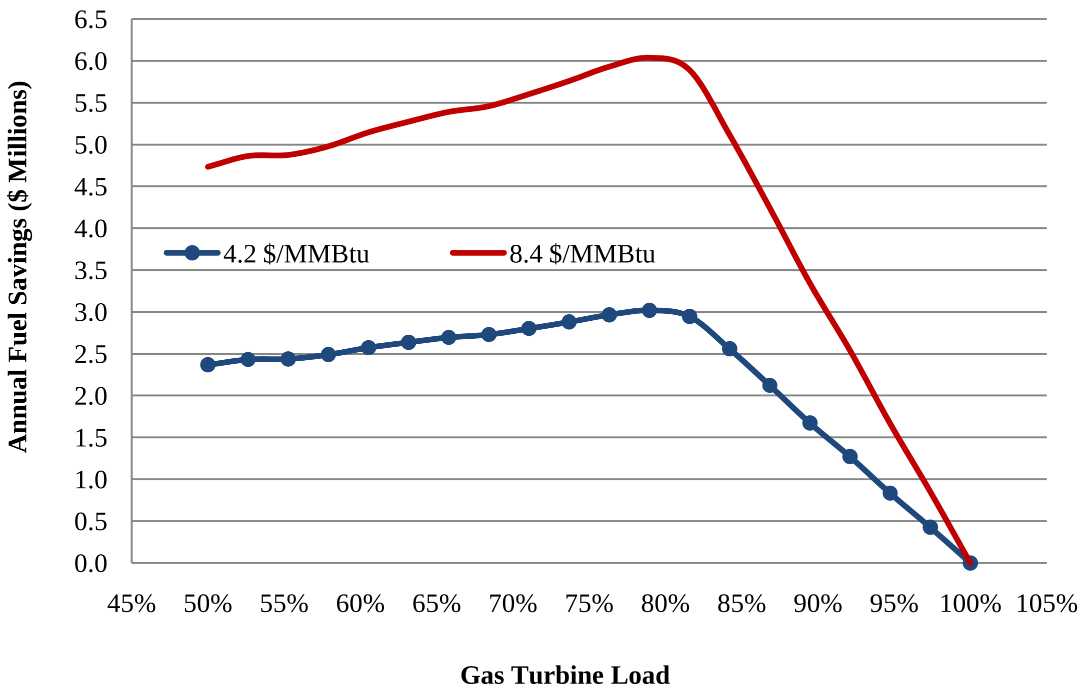


Figure 6-21: Annual Savings in fuel with gas turbine VIGV control compared to TIT control

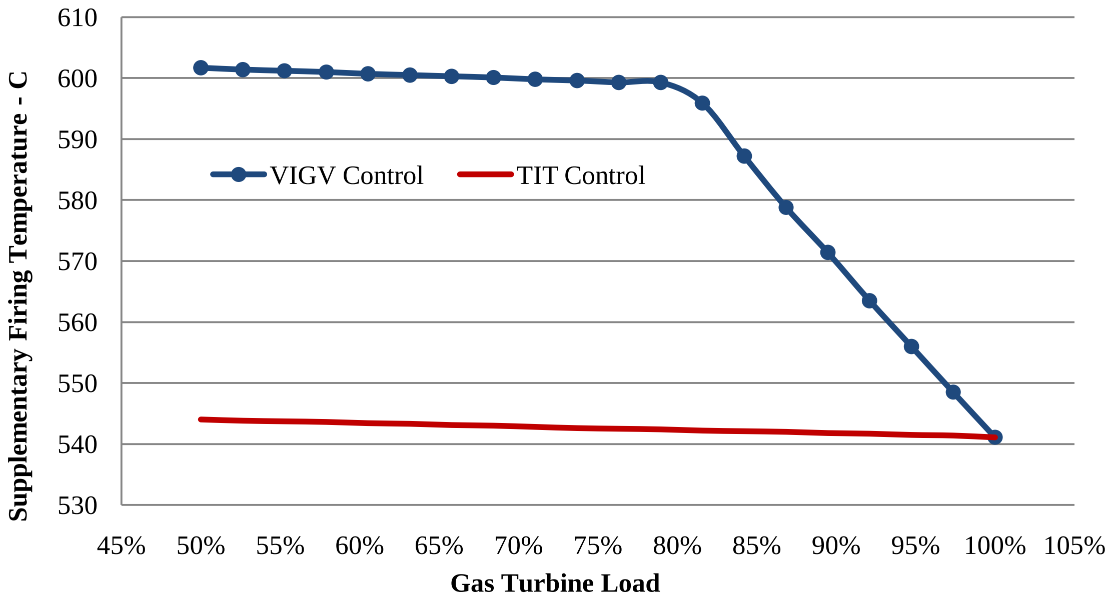


Figure 6-22: Effect of GT control in supplementary firing temperature

6.6 Economic Analyses

The first part of this chapter dealt with the thermodynamic performance of the considered cogeneration system. In the remaining part, the economics of the S-EOR project is evaluated using TERM-EOR. To examine the impacts of cogeneration on the project's economics, the project is evaluated with and without incorporating cogeneration. The baseline assumptions used in the analyses are listed in Table 6-4[36]. The project has a 20 yeas operating life and takes three years to commission. The year at which production commences is used as the reference year for discounting. The gas turbine is assumed to have an annual load factor of 85% and is operated with VIGV part-load control.

Oil companies with on-site cogeneration are faced with the decision whether to classify the cogeneration unit within the fence or outside the fence (Nicole, et al., 2005). The classification is important because it affects fiscal arrangements. If the cogeneration is considered outside the fence then the oil company is responsible for the investment and operation of the unit. In this case, revenues from excess electricity are not shared with

[36] The sensitivity of the project economics to variations in some of the baseline assumptions is considered later

the government and thus do not go through the petroleum fiscal systems[37]. On the other hand, if the cogeneration is considered part of the S-EOR investment then the oil company is eligible for both CAPEX and OPEX reimbursement. However, revenues from selling excess electricity are added to the project gross revenue and are therefore shared with the government. In this case study, the cogeneration is considered outside the fence and is operated by the oil company, and is treated under different tax system which is in accordance with utility-based tax system, see Table 6-4.

Table 6-4: Key assumptions

Parameter	Unit	Baseline Value
Project start year	-	2011
Project life	-	20
Years to commission	-	3
Discount rate	%	10
Oil price	$/bbl	50
Natural gas price	$/MMBtu	4.2
Grid electricity tariff	cents/kWh	8
Operating cost target	$/bbl	20
Non-thermal cost	$/bbl	5
CO_2 tax	$/tonne	0
GT Load	%	85
Ambient temperature	°C	28
Fired-Boiler rated capacity	MMBtu/hour	50
Royalty Rate	%	0.0
Government Share	%	60
Oil Company Share	%	40
Cost Oil	%	70
Income Tax – Petroleum	%	35
Income Tax- Electricity	%	30

[37] In a royalty/tax system, for example, the revenues from the excess electricity are not included in the calculation of royalty payment

6.6.1 Electricity Generation Cost

On-site power consumption and the amount of excess power available for export, as determined by TERM-EOR, are shown in Figure 6-23. It is estimated that only about 20% of the generated power will be consumed by the S-EOR project, with the remaining 80% being available for export.

The methodology outlined in section 5.4.4.1 is used to calculate the levelized cost of electricity (LCOE) at various operating scenarios. The effect of running the GT as part-load on the LCOE is shown in Figure 6-24. It can be seen that the cost of generating electricity increases as the GT is run at lower power settings than its rated value. Figure 6-24 indicates that the LCOE has increases by more than 25% as a result of reducing the GT output from baseload to 50% load. The higher operating cost is primarily caused by the lower thermal efficiency of the GT at part load, as well as slower amortization of the capital. Figure 6-24 also shows the impact of fuel price escalation on the LCOE. It is clear that fuel price escalation will have a significant impact of the cost of generating electricity. For example, at 85% GT load the LCOE increased from 6.15 to 11 cent/kWh when natural gas price increased from 4.2 to 8.4 \$/MMBtu.

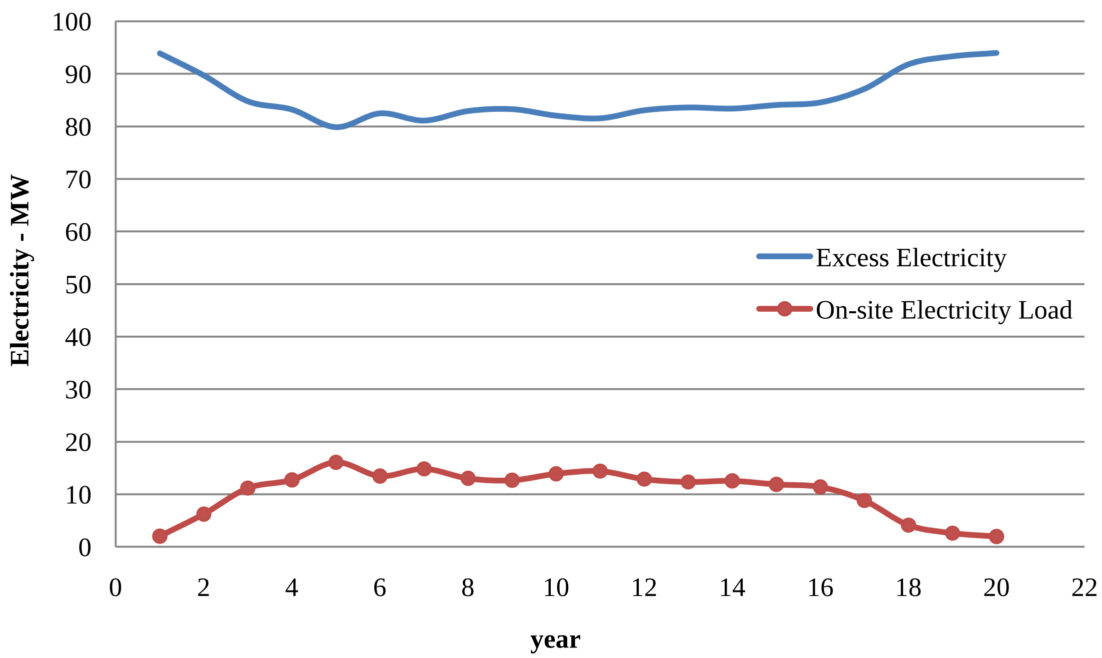


Figure 6-23: On-site and excess electricity curves

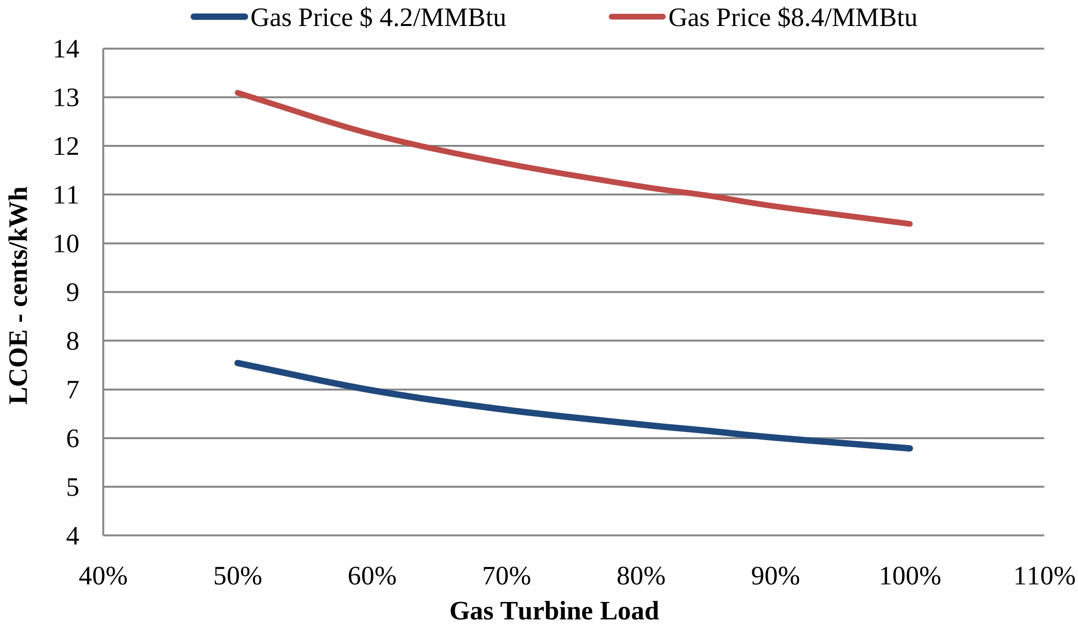


Figure 6-24: Levelized cost of electricity as function of gas turbine load

6.6.2 Steam Generation Cost

The calculated total steam generating cost includes capital, maintenance, and fuel costs. The latter is typically the largest cost component in S-EOR projects. Fuel consumption per barrel of oil produced, and thus fuel cost, is primarily influenced by the efficiency of the recovery process, which is reflected in the SOR, and the efficiency of the steam generation process.

The project average fuel consumption per barrel of oil produced is shown in Figure 6-25. The variation in natural gas consumption throughout the project operating life is readily apparent. For the conventional system, natural gas consumption varies from 985 to 3300 cf/bbl. This variation in fuel consumption is mainly driven by the variation in the field SOR. The deteriorating SOR profile toward the end of the project life and the consequence increase in fuel cost may require steam injection rate to be reduced in an effort to cut cost and prolong the project economic life. This corrective action has to be weighed against lower oil rate that may result as steam injection rate is reduced. In this case study, the steam injection rate is planned to be reduced after 16 years of operation despite the fact that it will determinately impact the oil rate, see Figure 6-7.

For the cogeneration case, fuel consumption varies from ‘zero’ to 1230 cf/bbl. In the first year, the full steam demand is met by recovering the heat from the GT exhaust, resulting in ‘zero’ fuel consumption. In later years, the amount of steam produced by recovering GT exhaust is insufficient to meet the field full steam demand, and thus supplementary firing is used to boost steam production. In addition, TERM-EOR estimated that 12 fired boilers will be needed after the 4th year of operation to meet the peak steam demand. Therefore, fuel consumptions increases as more steam is generated using HRSG supplementary firing or fired boilers.

An interesting observation is what happens to natural gas consumption in the cogeneration case. Despite the deteriorating SOR profile, gas consumption actually drops. The reason for this is that as steam injection rate is reduced, a larger proportional of the required steam is cogenerated, and thus less fuel is consumed. Therefore, the overall recovery process becomes more efficient despite the higher SOR.

The acceptable steam to oil ratio, introduced in section 5.4.3, is plotted in Figure 6-26. Figure 6-26 indicates that the acceptable SOR for the conventional system remains roughly unchanged throughout the project life. This is because the acceptable SOR is primarily determined by steam cost which is in turn influenced by the steam technology employed and the fuel price. In these set of simulations, the fuel price is assumed constant and the part load performance of fired boilers does not vary significantly with changing load. For these two reasons, the steam cost of the conventional system is approximately constant, and thus results in a constant acceptable SOR. The case for cogeneration is, however, more dynamic because the steam cost is influenced by the fuel price, the GT load, the amount of supplementary firing, additional fired boilers etc. Variation in one, or more, of these factors will be reflected in variation in the acceptable SOR. Figure 6-27 shows that the acceptable SOR for the cogeneration varies wildly from 9 to 18.

Figure 6-27 shows the impact of the GT load on the unit cost of steam. Steam cost increased from 7.3 $/ton at GT load of 100% to 9.7 $/ton at GT of 50% i.e. more than 30% increase in steam cost.

The total cost of producing a barrel of oil is shown in Figure 6-28. At natural gas price of 4.2 $/MMBtu, the unit cost for the cogeneration project varies from 6.4 to 13.9 $/bbl of oil produced whereas for the conventional fired boilers project it varies from 11.4 to 26.7 $/bbl. For the cogeneration case, the unit cost is on average 3-4 dollar lower than the fired boilers system. This is a substantial amount given the large sizes of S-EOR projects. Figure 6-28 also explain the need to cut steam injection rate for the conventional system toward the end of the project life is obvious. The cost almost doubled from an average of 13 $/bbl to 26 $/bbl. This may render the project uneconomic if it coincides with low crude prices. This is in contrast to the cogeneration project where the unit cost decreases[38] toward the end of the project when steam injection is reduced as a result of the reservoir heat management program. It can therefore be argued that the decision to reduce steam injection rate, and consequently lower oil rates, could have be different if the decision was made based on a proper knowledge of the characteristics of surfaced steam technologies. In other words, the decision-making process could be mislead by simply assuming that higher SORs are intolerable and thus steam injection rate has to be reduced despite the fact that it would potentially result in lower oil production rate.

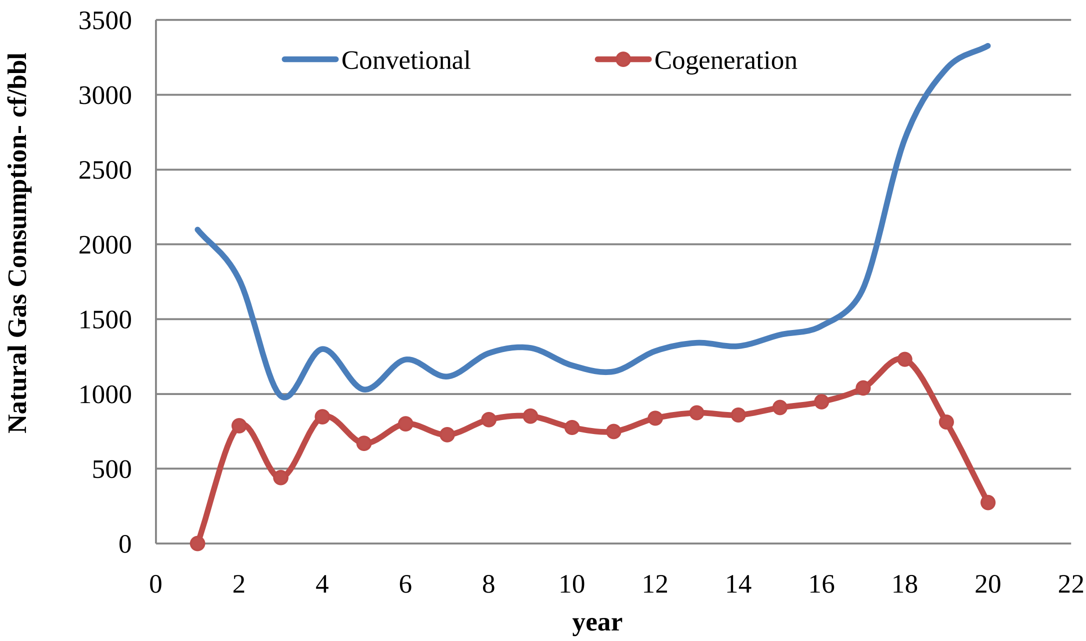


Figure 6-25: Comparison of average natural gas consumption per barrel of oil produced

[38] This is because most of the required seam is cogenerated, and thus the need for supplementary firing and back-up boilers is eliminated

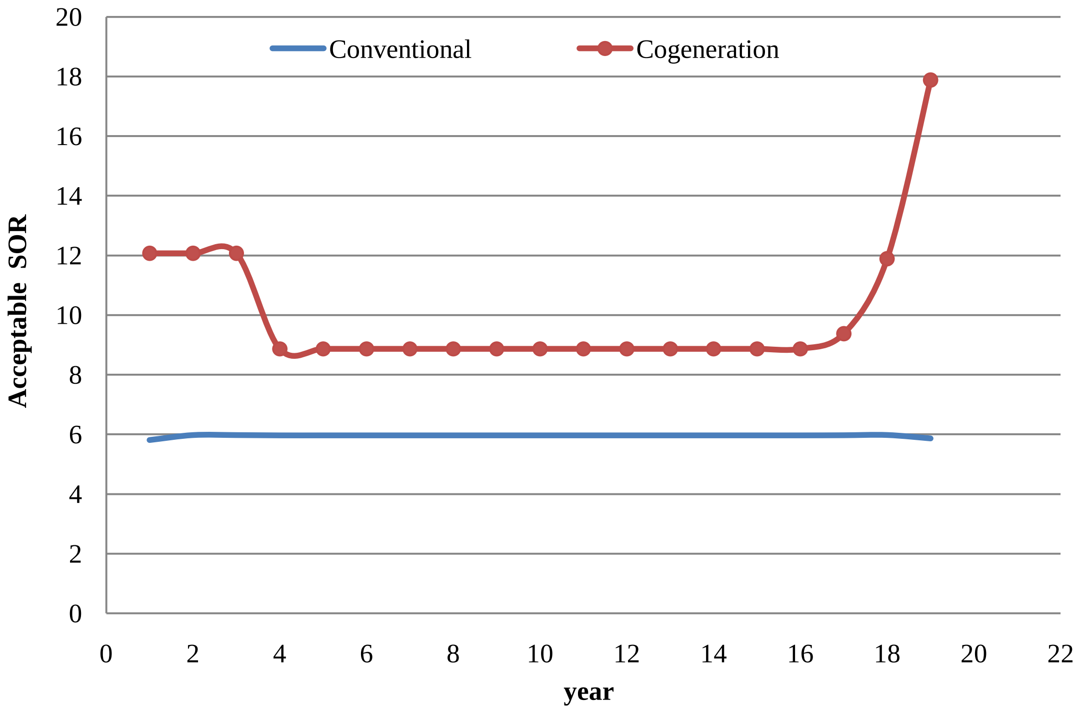


Figure 6-26: The acceptable SOR for conventional and cogeneration systems

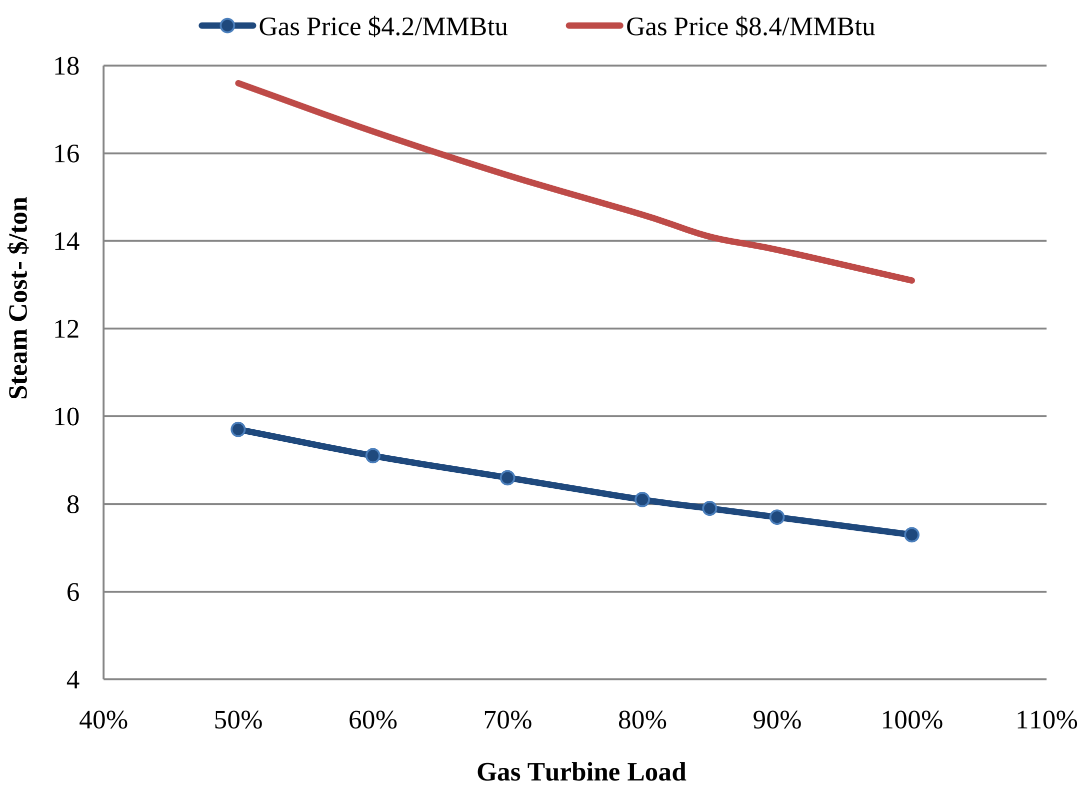


Figure 6-27: Steam cost as a function of the gas turbine load

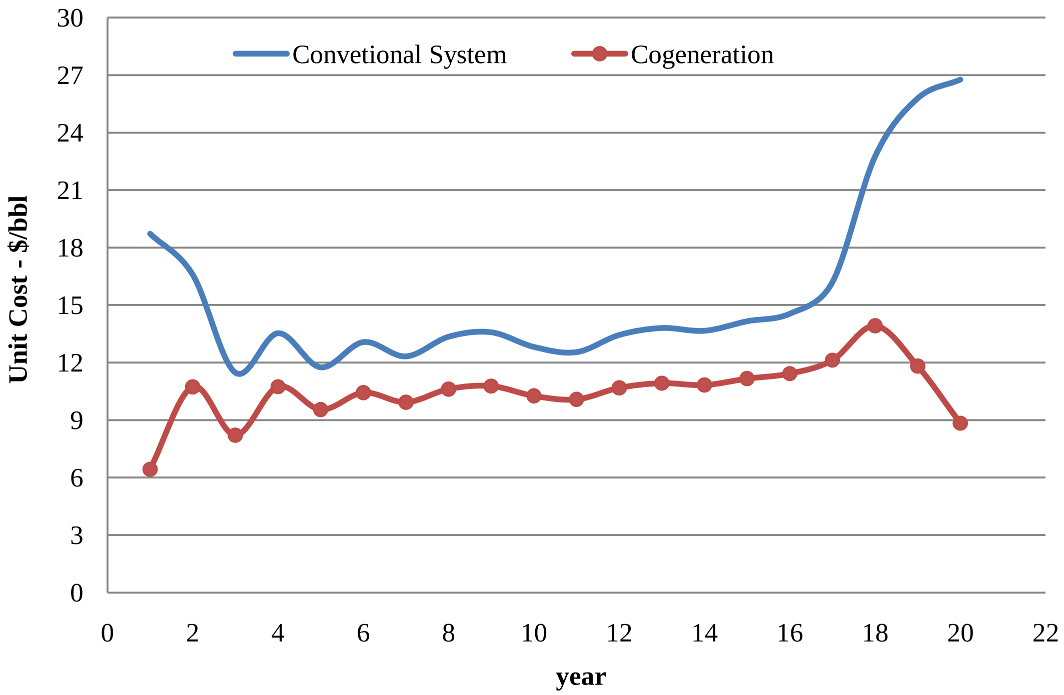


Figure 6-28: Unit cost of oil –including thermal and non-thermal costs

6.6.3 Project NPV Analyses

Figure 6-29 shows the total savings, in terms of undiscounted cash flows, due to cogeneration as a function of the GT load and fuel price. Not surprisingly, the maximum saving is attained at high GT load and high fuel prices. In this case study, the amount of potential saving varies from 380 to over 1000 $MM, depending on the GT load and fuel price. The saving is then split between the oil company and the host government according to the fiscal system agreement.

The government and oil company NPVs at different operating scenarios are shown in Figures 6-30 to 6-33. Figure 6-30 indicates that the government is saving over 140 $MM of discounted cash flow by opting for the cogeneration option. Figure 6-30 also shows that the economics of the project deteriorates significantly by using crude oil for steam generation. More than one billion of the projected NPV is lost in this case. The economics of oil-fired cogeneration is less sensitive to the decision to use crude oil. This is because cogeneration is more efficient and thus uses less fuel. In addition, crude oil is only used for supplementary firing and back-up boilers whereas the GT is run on natural gas.

The oil company seems to be more sensitive to changes in operating conditions. The NPV of the oil company drastically dropped for the conventional system from 356 $MM to (-109) $MM by the decision of using crude oil for steam production. This reinforces the argument made in Chapter Three about the economic issues of burning produced oil for steam generation. For cogeneration, the economic prospects remain good even for the crude oil case. Cogeneration is calculated to result in a total saving of 125 $MM for the oil company.

S-EOR projects are also known to be greatly influenced by oil prices and that they need relatively high oil prices to be economically viable. Figure 6-32 indicated that the breakeven crude oil price for the conventional system is about 35 $/bbl and 29 $/bbl for the cogeneration system. At a higher natural gas price (8.4 $/MMBtu), breakeven price is predicted to increase to 41 $/bbl and 33 $/bbl for the conventional and cogenerations systems respectively.

The impacts of changing the tariff of the excess electricity sold to the gird on the oil company economics have been evaluated. Figure 6-33 shows the oil company NPV at different assumed electricity tariffs. The LCOE at this operating scenario was calculated at 6.15 cents/ kWh. The tariff range is elected to cover values below and above the calculated LCOE. Surprisingly, the economics of cogeneration was better than the conventional system even with the selling tariff lower than the LCOE. This indicates that the amount of saving obtained from cogeneration is large and that cogeneration economics is robust.

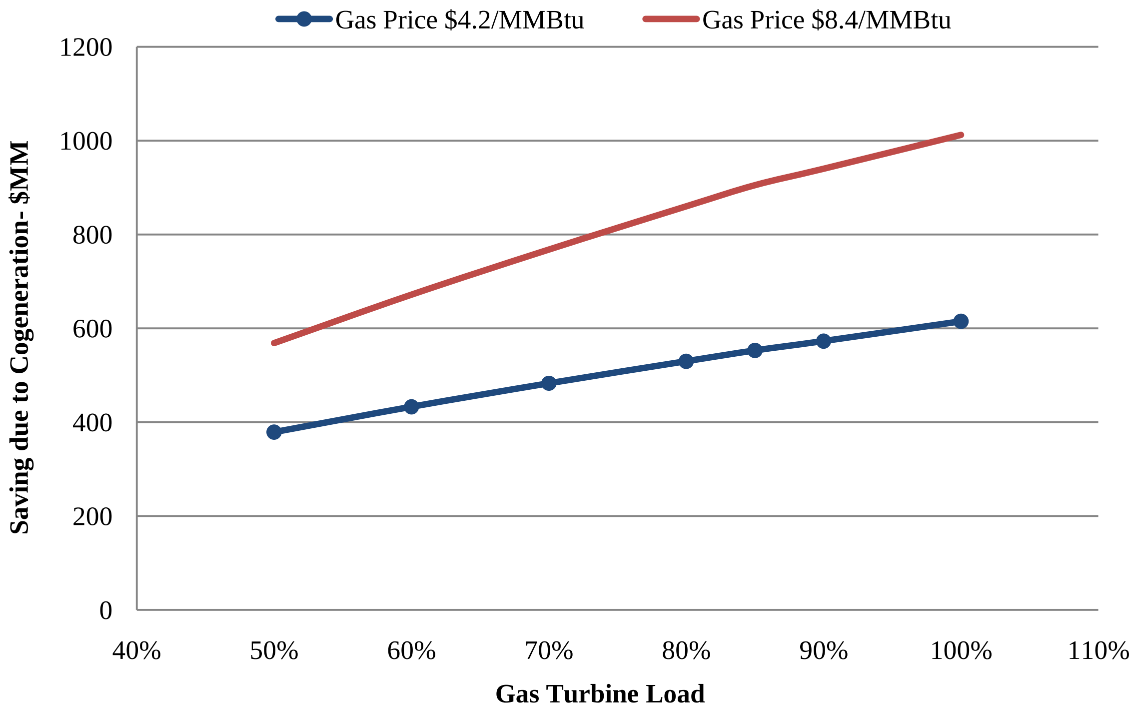


Figure 6-29: Total undiscounted saving due to cogeneration as a function of GT Load

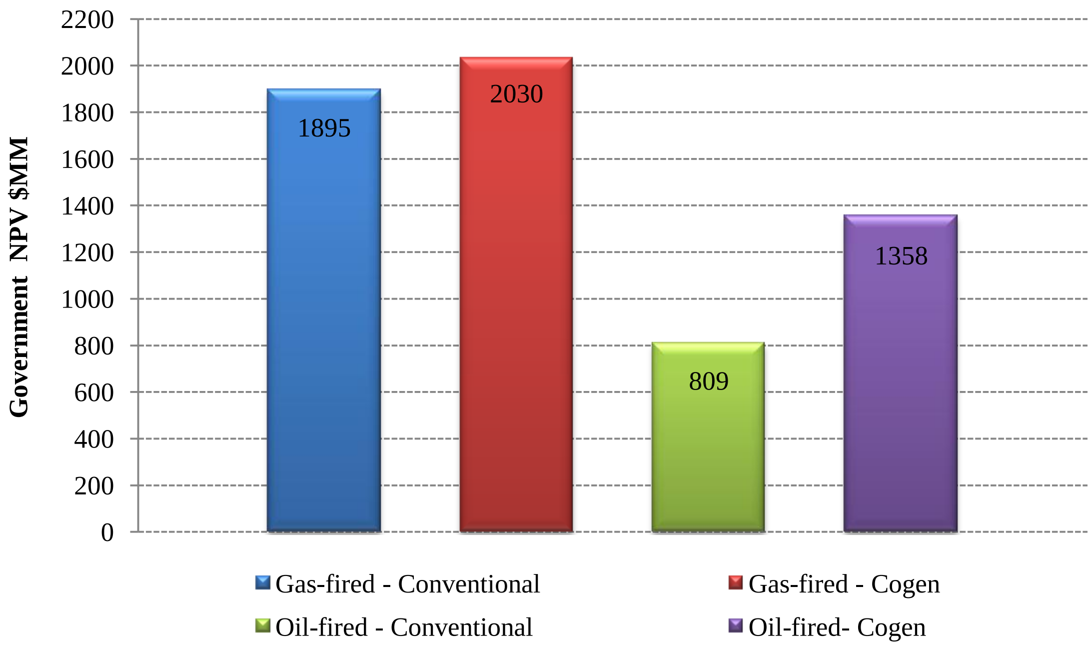


Figure 6-30: Government NPV at different operating scenarios

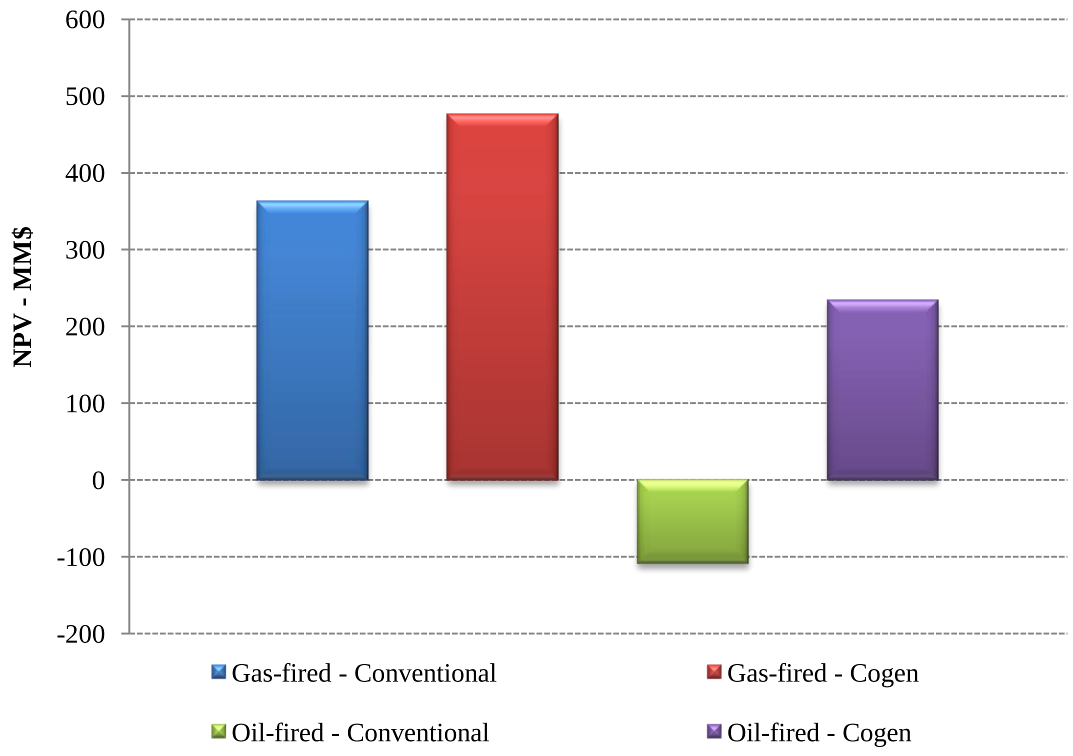


Figure 6-31: Oil company NPV at different operating scenario

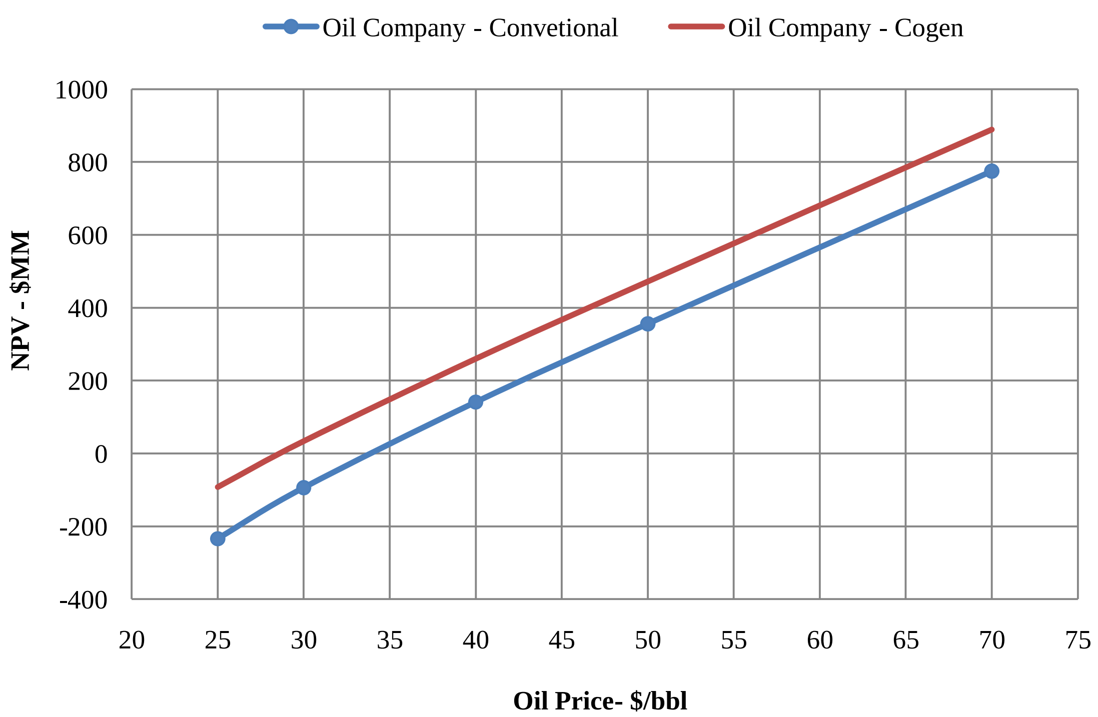


Figure 6-32: Oil company NPV as a function of oil price

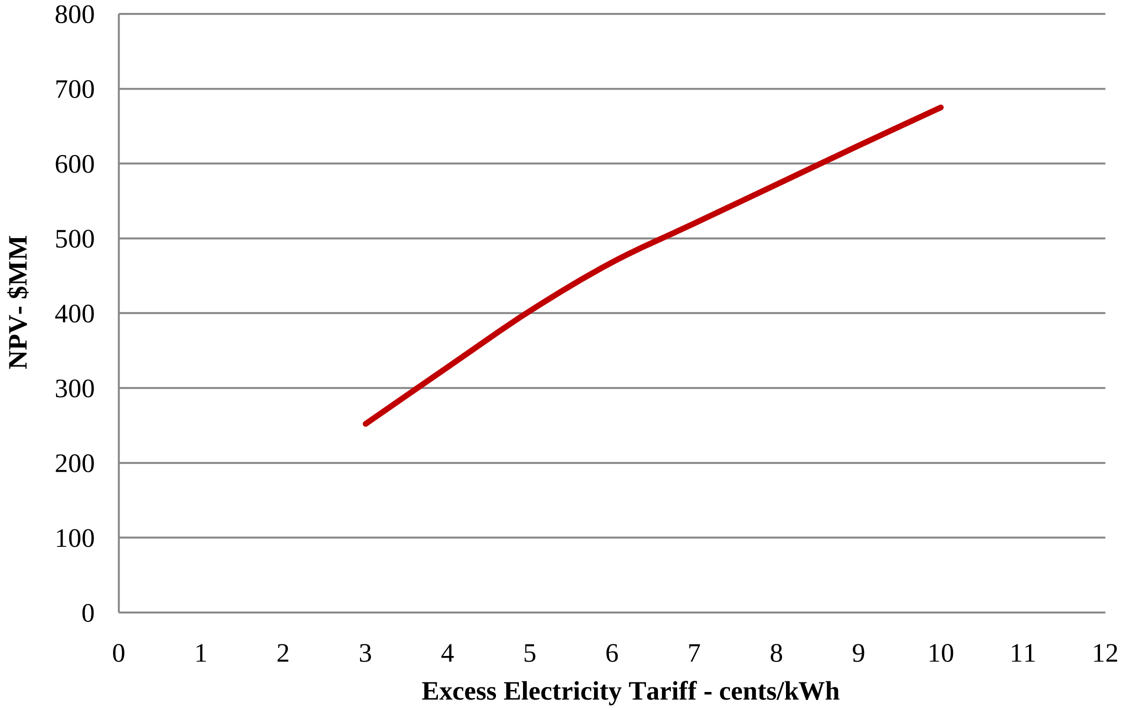


Figure 6-33: Effect of excess electricity tariff on the oil company NPV

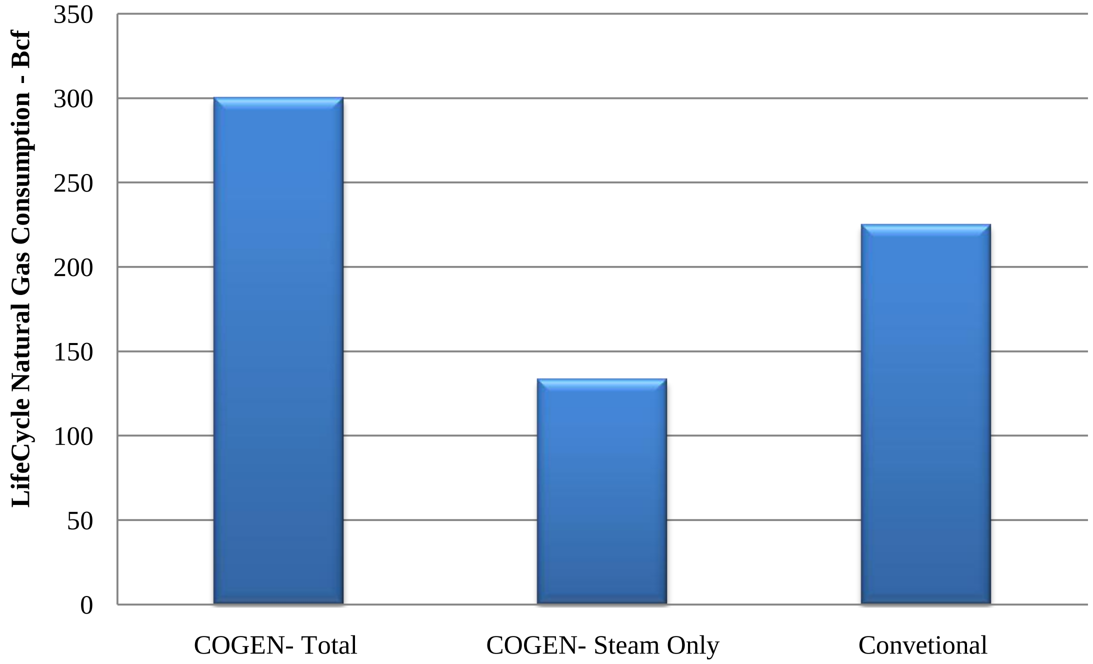


Figure 6-34: Lifecycle natural gas consumption

7 Case Study Two: Operating Pressure for SAGD Projects

7.1 Introduction

SAGD has now been tested and is technically approved as an effective method for recovering heavy oil and bitumen. However, it is still arguable for many of the process parameters whether they are being operated at optimum conditions. An example of this in recent years is whether it will be more beneficial to inject steam at low pressures (LP-SAGD) instead of the currently practised high pressure injection (HP-SAGD). There are some who believe that LP-SAGD is thermally more efficient because it results in lower SOR profile compared to HP-SAGD (Edmunds, et al., 2001). They argue that for optimum economics, SAGD process must be thermally efficient and that the process economics is more sensitive to the SOR profile that is obtained rather than the oil rate per well.

On the other hand, there are others who believe that SAGD economics is more sensitive to the oil rate obtained and that there are fewer thermal benefits in LP-SAGD when the evaluation process includes surface operations, (Collins, 2007). Collins demonstrated that higher oil rates are obtained by operating at higher pressures and that the lower thermal efficiency of this process can be improved by recovering part of the heat contained in the produced fluids. SAGD produces hot fluids continuously at constant rates and at temperature just below the saturation temperature of the injected steam. Collins argues that if this energy is recovered, and used for example to preheat the feedwater to steam generators, it can enhance the overall efficiency of the recovery process while still maintaining high oil rates.

In this chapter, TERM-EOR is used to carry out a comprehensive and multidisciplinary evaluation of a typical SAGD project operating at different injection pressures. First, analytical predictions of oil rate and SOR versus pressure are considered. Secondly, the effects of pressure on steam rate, fuel consumption, and CO_2 emission are illustrated. Finally, the effects of operating pressure on the project life-cycle economics are calculated from the prospective of both an oil company and a host government.

7.2 Theoretical Background

The effect of pressure on SAGD performance is relatively well understood; the recovery mechanism is gravity-driven and does not depend on any pressure gradient (Edmunds, et al., 2001). The operating pressure, however, has a pronounced impact on the oil viscosity (reduction that can be obtained, and thus the achievable oil rate. Viscosity reduction is larger at higher temperatures. Steam temperature is a function of steam pressure and it increases as pressure increases, see Figure 7-1. Therefore, operating at higher pressures, thus higher temperatures, is expected to yield higher oil rates.

Both Butler (1994) and Reis (1992) analytical models predict that oil rate will be inversely proportional to the square root of oil viscosity at steam temperature (, see Equation 7-1 (Reis model). Edmunds, et al (2001) predicted a six-fold increase in oil rate between atmospheric pressure and 100 bar. The advantage of operating at higher pressures is therefore clear.

Equation 7-1

The increase in oil rate, however, has to be weighed against the fact that HP-SAGD is thermally less efficient. The primary reason for this is that the latent heat (L_s) fraction of the injected steam provides the dominant source of heat for reservoir heating in SAGD. This can be readily observed from Equation[39]7-2, which shows that only the latent heat fraction is accounted for in the calculation of the SOR. Since steam at lower pressures has greater proportion of its heat as latent heat, refer to Figure 7-2, one can see the attraction of LP-SAGD from energy viewpoint. Therefore, lower steam consumption is expected with LP-SAGD, which is reflected in lower SOR profile. A second reason for the better efficiency with LP-SAGD is the lower difference between the injected steam temperature and the reservoir temperature ( ), which results in lower heat losses to the formation.

Equation 7-2

[39]Based on Reis analytical model described in Section 5.2.1

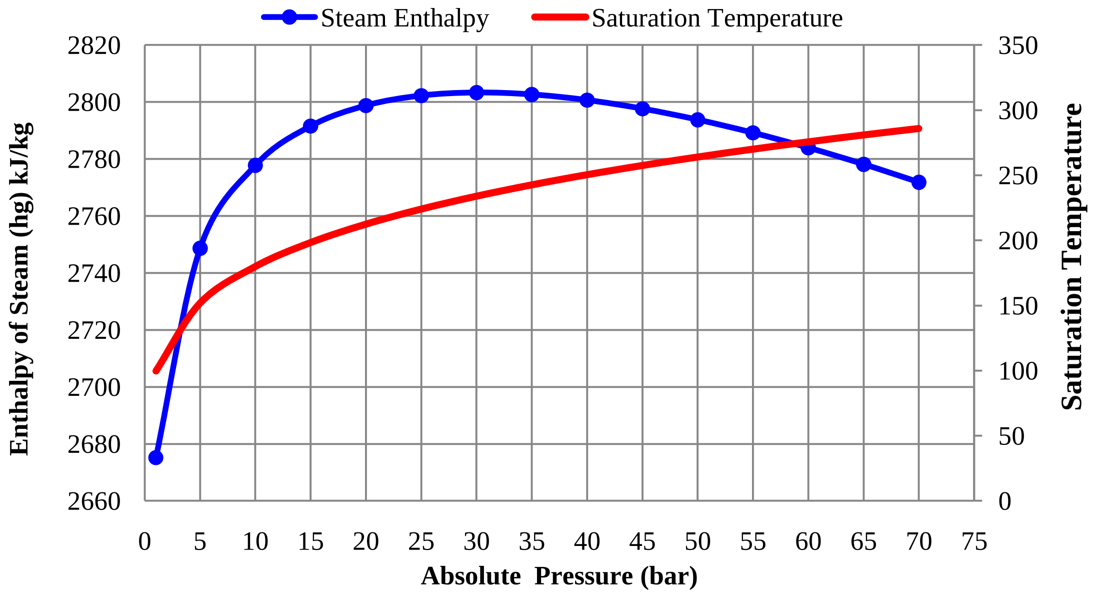


Figure 7-1: Saturated steam temperature and enthalpy as a function of pressure

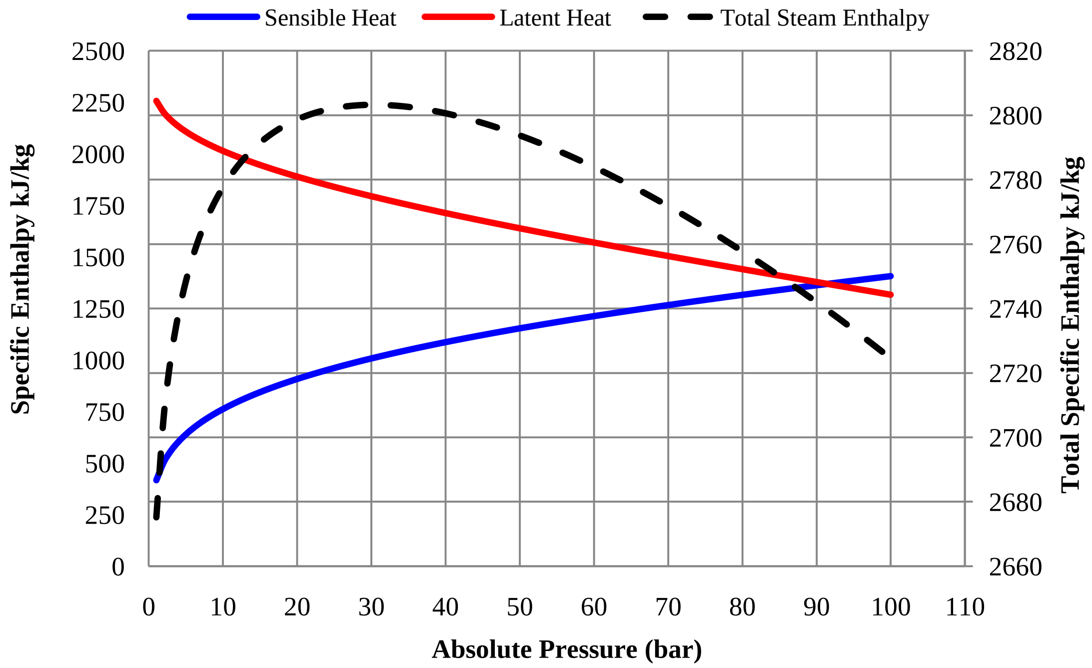


Figure 7-2: Saturated steam temperature and enthalpies as a function of pressure

7.3 Subsurface Model

Reis's SAGD model described in Section 5.2.1 is used to predict the oil rate and the steam requirement for the different operation pressures considered. A series of simulations were performed at three pressure levels: 15, 30, and 45 bar. The reservoir and fluids properties used in the simulations are listed in Table 7-1.

Table 7-1: Reservoir parameters for Reis SAGD model

Parameter	Unit	Input
Injection Pressure, P	bar	15,30,45
Reservoir Temperature, T_r	°C	50
Formation Heat Capacity, M	J/ C.m^3	2.28
Reservoir Thickness, H	m	30
Thermal Diffusivity, α	m^3/d	0.0557
Porosity, Φ	%	32
Initial Oil Saturation, S_o	%	85
Residual Oil Saturation, S_R	%	15
Effective Permeability for Oil, k	m^2	6.9E-12
Oil Density, ρ	gm/cc	0.98
Constant, a	-	0.4
Constant, m		3.6
Reservoir Width , W	m	40
Steam Quality	%	100
Producing well Length	-	500

7.4 Surface Facility Modelling

In order to examine the effect of the characteristics of surface steam facility on the decision-making process, the three operating scenarios are evaluated based on both conventional boilers system as well as cogeneration. These systems are described in more details in Chapters Three and Six. The steam and oil rates predicted by the subsurface model are fed into TERM-EOR for performance and economic evaluations. Performance parameters such as total capital investment, fuel consumption, CO_2 emission, NPV are some of the outputs from TERM-EOR that are considered in this case study.

7.5 Baseline Economic & Fiscal Assumptions

Some of the main inputs to the economic and fiscal models are listed in Table 7-2. In order to examine the sensitivity of the decision-making process to changes in the prevailing economic conditions, the economics of the project is also be evaluated under various crude oil and natural gas prices. Monte Carlo simulation technique is later used to quantify the financial risk associated with the various operating strategies considered.

Table 7-2: Baseline economic and fiscal inputs

Parameter	Unit	Input
Oil Price	$	50
Natural Gas Price	$/MMBtu	4.2
Cost-Oil Percentage	%	70
Profit Oil Split- Government	%	60
Profit Oil Split- Oil Company	%	40
Income tax	%	35

7.6 Results and Discussions

7.6.1 Oil Rate & SOR

The predicted oil rate for the three operating pressures is shown in Figure7-3. As will be expected, higher oil rates are obtained at higher operating pressures. It can also be the incremental increase in oil rate due to higher operating pressure diminishes as the operating pressure gets higher. For example, a 30% increase in oil rate is predicted by increasing the steam injection pressure from 15 to 30 bar, whereas only 21% increase is for the range between 30 to 45 bar.

The predicted SOR profile for the three operating pressures is shown in Figure 7-4. It can be readily seen that operating at higher pressure will have detrimental effect on the field SOR profile. For example, after 20 years of operation, the predicted SOR for 45 bar is 64% more than at 15 bar. This is a substantial difference in SOR that will have deleterious impacts on the project's profitability, as will be illustrated later.

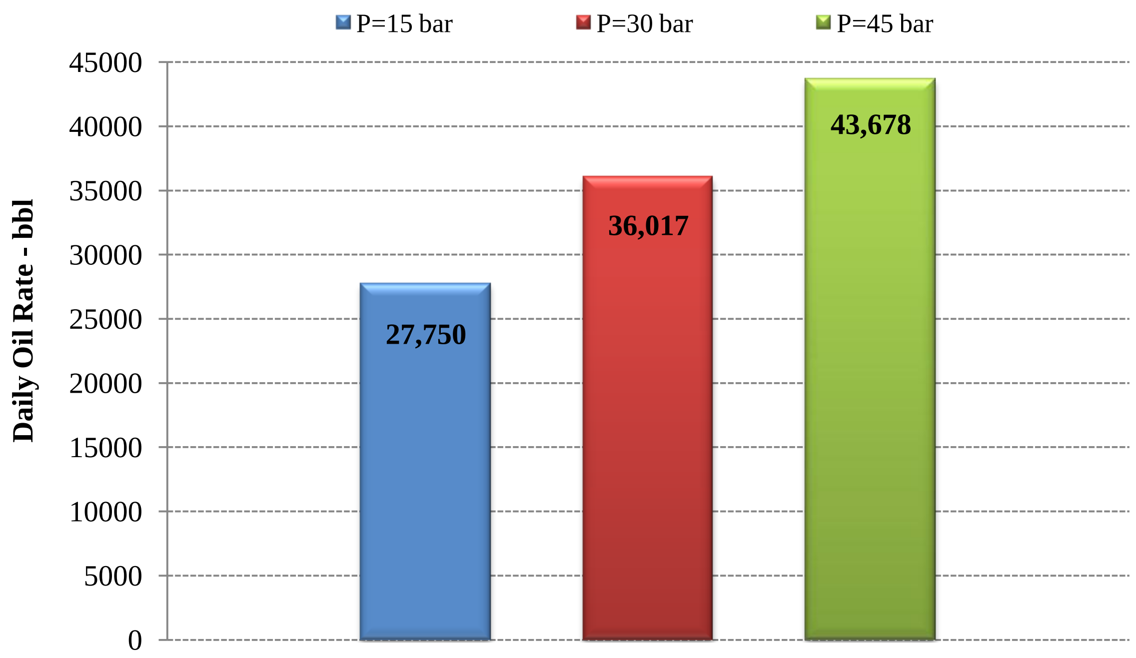


Figure 7-3: Predicted oil rate at various operating pressure

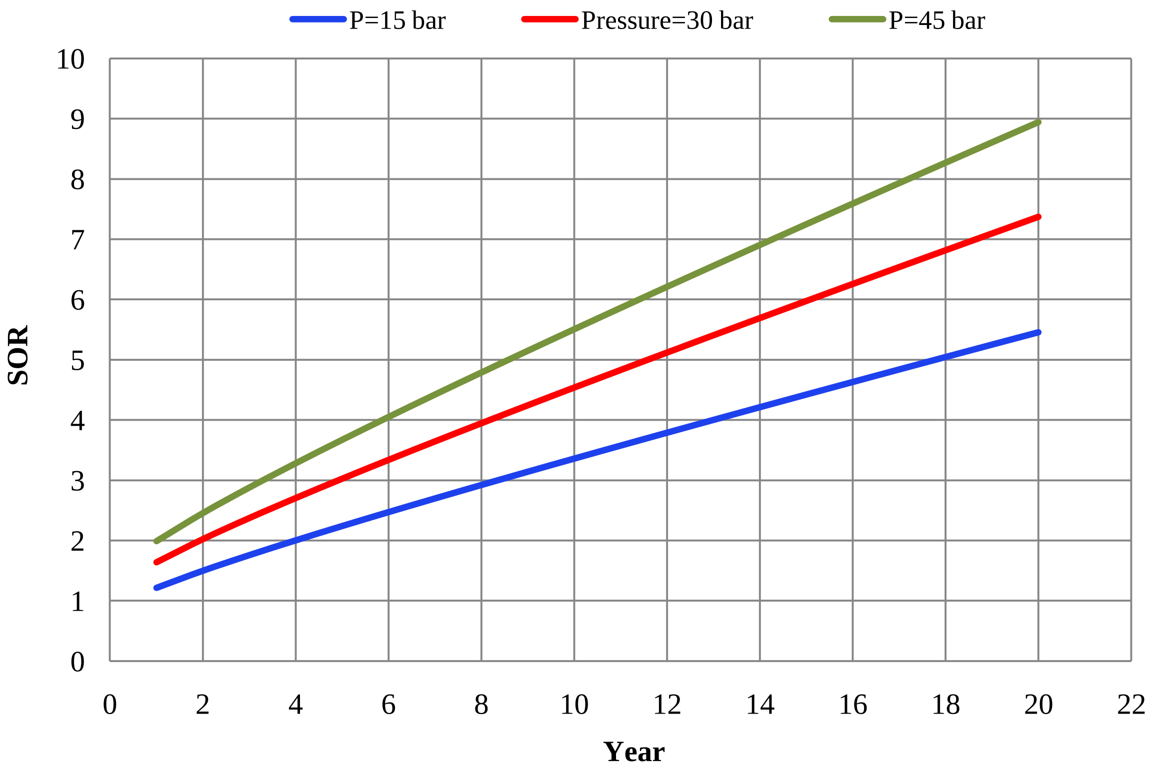


Figure 7-4: Effect of operating pressure on the field SOR profile

7.6.2 Steam Injection Rate

The predicted steam injection profiles for the three operating scenarios are shown in Figure 7-5. As discussed previously, steam consumption increases as the operating pressure increases in order to compensate for the lower latent heat content. As a result, more steam generators will be required for high pressure injection to handle the additional steam capacity, see Figure 7-6. The number of steam generators required is calculated based on a typical 50 MMBtu/hour oil field steam generator capacity.

The total capital requirement as estimated by TERM-EOR is shown in Figure 7-7. Figure 7-7 indicates that almost 50% more capital is needed for the 30 bar as compared to the 15 bar injection pressure. This is mainly due to the additional steam generators, larger number of steam injectors, and larger water treatment facility in the 30 bar case. It is worth noting, however, that in the calculation of capital investment it is assumed that the steam facility is sized to meet the field's maximum steam demand instead of expanding the steam facility incrementally as the demand for steam increases. This is despite the fact that this maximum will only occur toward the end of the project operating life.

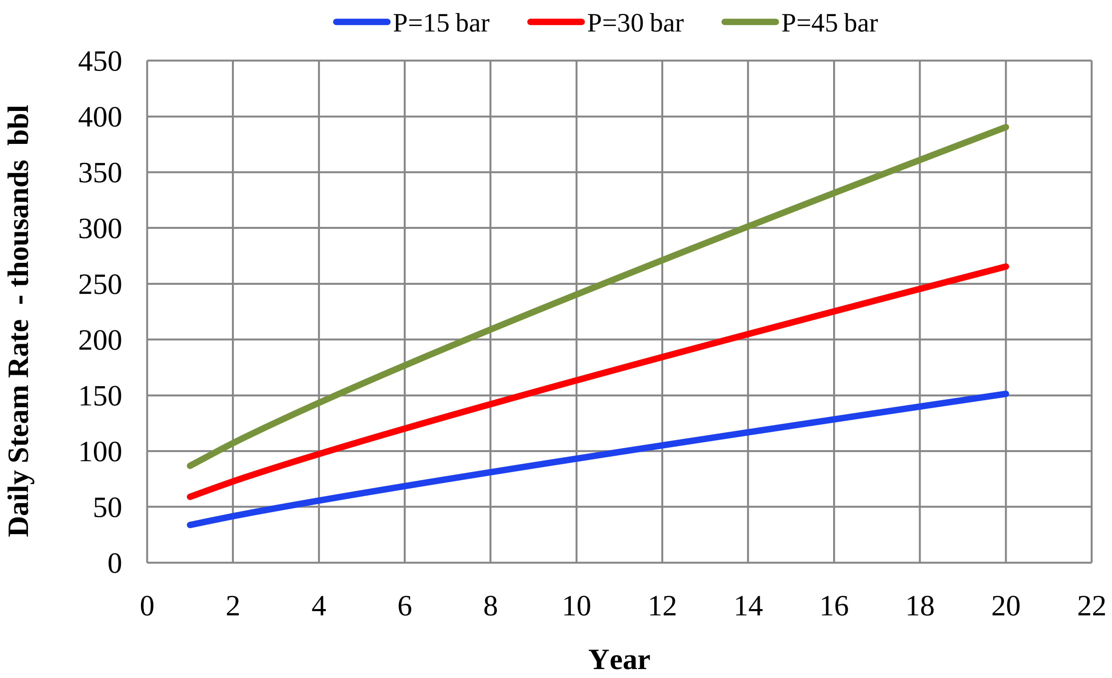


Figure 7-5: Predicted steam requirements at different operation pressure

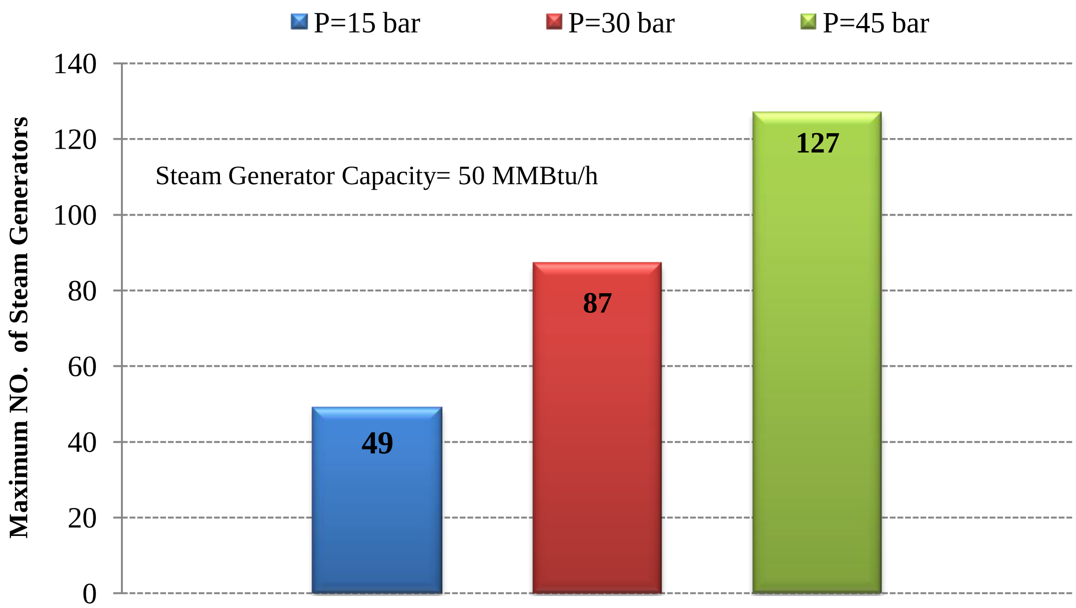


Figure 7-6: The effect of operating pressure on the field steam generator requirement

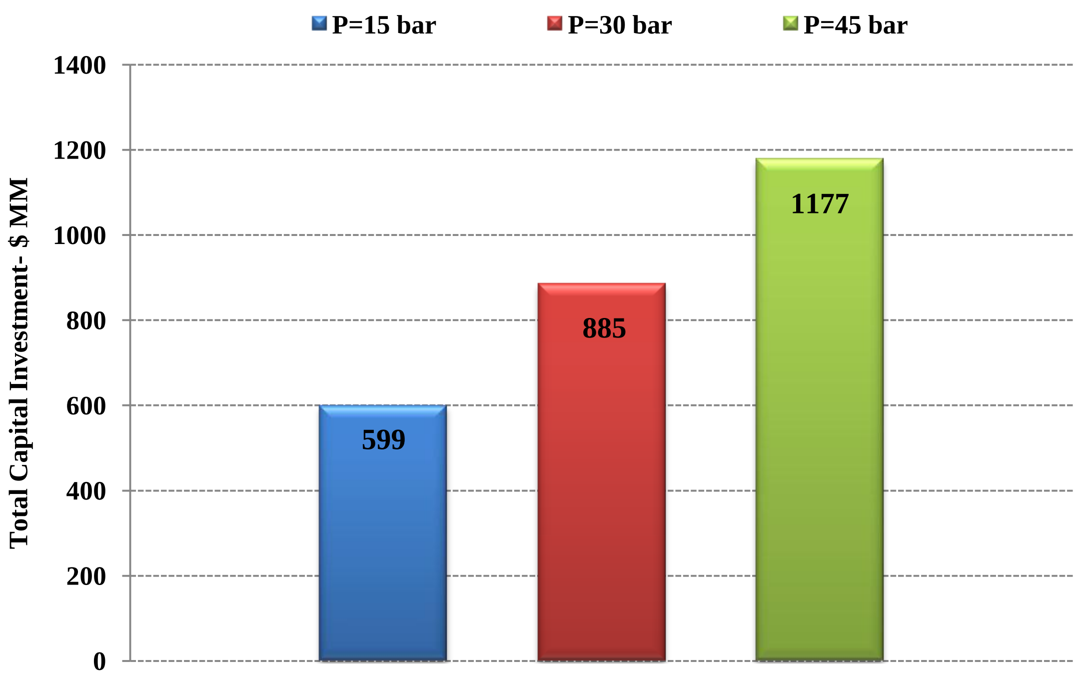


Figure 7-7: The effect of operating pressure on the total capital requirement

7.6.3 Natural Gas Consumption & CO_2 Emissions

It is well known that the cost of the fuel used for steam generation is the largest cost component in S-EOR projects. As demonstrated in Chapter Two, natural gas consumption is strongly related to the field SOR profile as well as the efficiency of the steam generation equipment.

The impact of steam injection pressure on the average and total life-cycle natural gas consumption is shown in Figure 7-8 and 7-9 respectively. Natural gas consumption increases from about 1340cf/bbl for the 15 bar to 2200cf/bbl for the 45 bar injection pressure i.e. a 63% increase in fuel consumption. As a result, the project life-cycle natural gas consumption increases from 272 to 700 billion cf, for a 20 years project life.

The increase in natural gas consumption is also accompanied by an increase in CO_2 emissions. The average and life-cycle CO_2 emissions as a function of operating pressure are shown in Figure 7-10 and 7-11 respectively. Figure 7-10 shows that increasing the injection pressure from 15 to 45 bar will result in an increase in the average CO_2 emission from 96 to 149 kg.CO_2/bbl. As a result, the project life-cycle CO_2 emission increases from 19460 to 47480 thousands tonne.

It is worth to note that natural gas consumption and CO_2 emission reported in this section are higher than those presented in chapter three. This is because the values reported here are the average life-cycle fuel consumptions and emission which account for the deteriorating SOR profile associated with maturing field operation. It is therefore evident that accurate estimation of these critical performance parameters require life-cycle assessment, and that the use of average values would seriously under-estimate the project actual economic and environmental performance.

Up until now, the conclusion is that operating at high pressure, although yield in higher oil rates, will result in increased fuel consumption and CO_2 emissions, as well as higher capital requirement. The question is whether the additional oil rate will offset the higher operating and capital requirements associated with high pressure operations. This is investigated in the following sections.

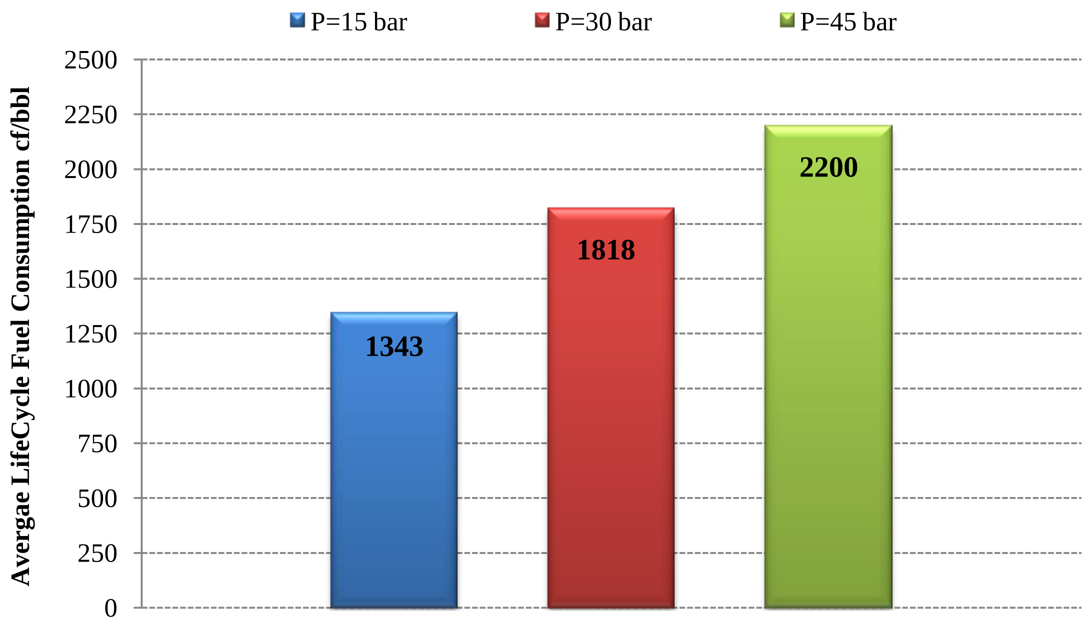


Figure 7-8: Average life-cycle fuel consumption at different operating pressure

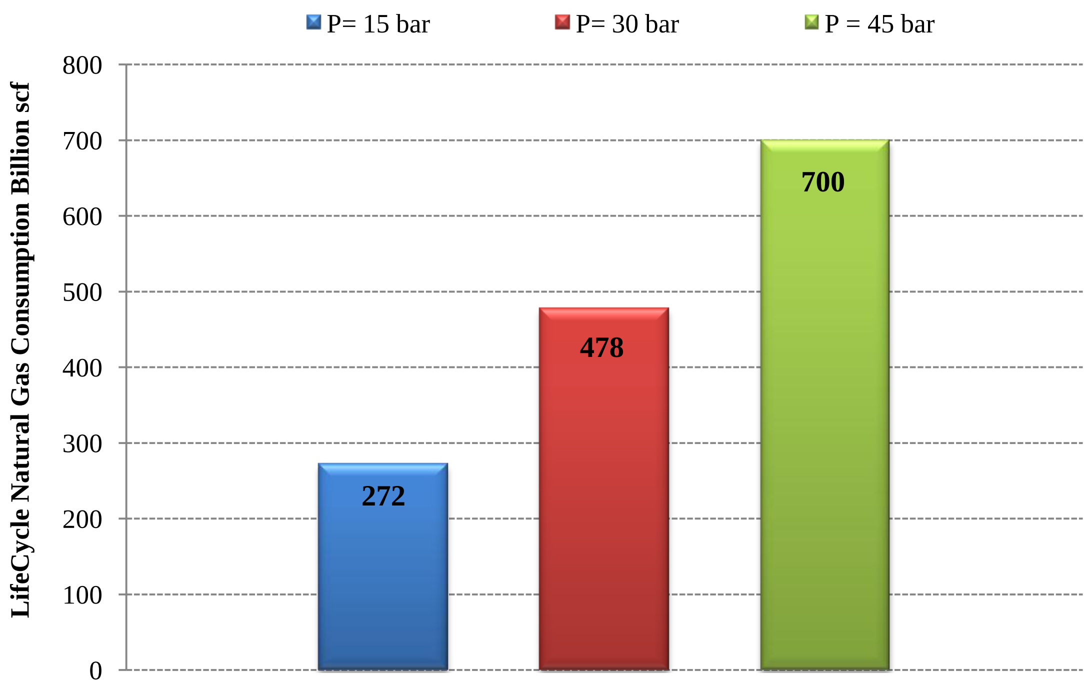


Figure 7-9: Total life-cycle fuel consumption at different operating pressure

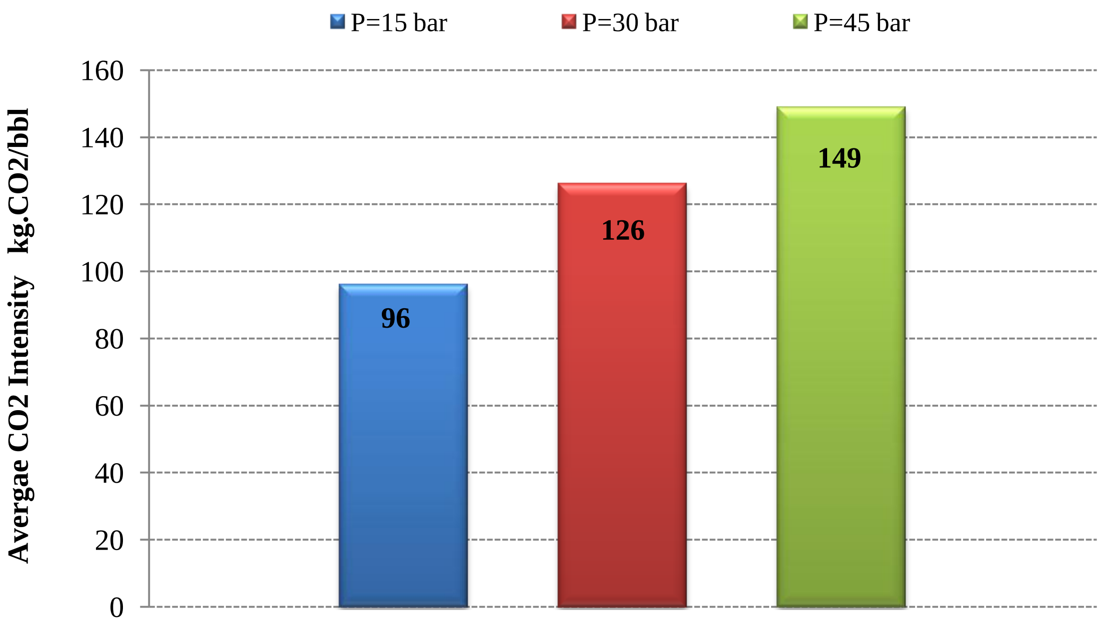


Figure 7-10: Average life-cycle fuel CO_2 emissions at different operating pressure

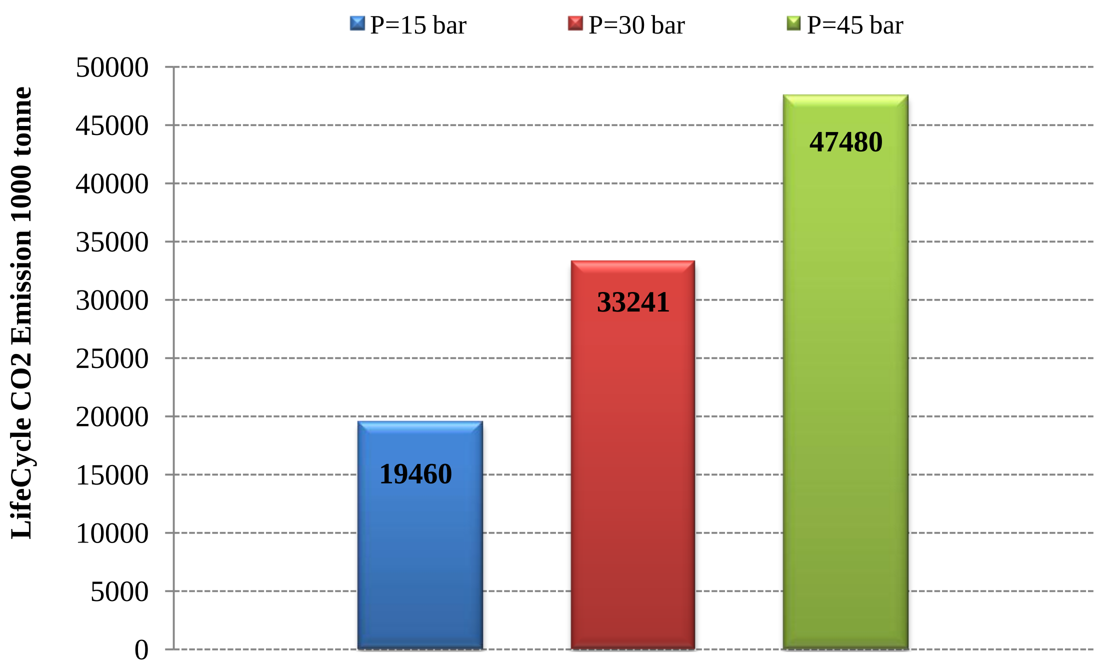


Figure 7-11: Total life-cycle fuel CO_2 emissions at different operating pressure

7.6.4 Oil Company NPV

It is clear from the previous discussions that, apart from the increase in oil rate, operating at high injection pressure would negative impacts on critical performance parameters such as the SOR profile, gas consumption, CO_2 emissions, and capital investment. There is therefore a need to assess quantitatively whether the anticipated increase in oil rate is adequate to compensate for other additional expenditures. The detailed engineering-economic model of TERM-EOR is used to evaluate the net present value (NPV) of the considered field the different operating pressures and economic assumptions.

The oil company NPV at different operating scansions is shown in Figure 7-12. Figure 7-12 indicates that it is neither the lowest (15 bar) nor the highest (45 bar) operating pressures that will maximize the oil company's NPV, but it is the 30bar. A 27 $MM will be lost if the field is operated at 45 bar instead of 30 bar. In this case, the additional revenue from the increased oil rate at 45 bar is simply not sufficient to offset the additional capital and operating costs.

An interesting observation was made when cogeneration was considered in the analysis. Incorporating cogeneration has altered the decision-making process by shifting the optimum injection pressure to 45 bar. In contrast to the previous simulations where conventional boilers were used, the NPV in the cogeneration case was found to be maximized at 45 bar injection, see Figure 7-13. This is because the improved thermodynamic efficiency of cogeneration makes the project economics less sensitive to fuel cost; thus shifting the balance in favour of the option with higher oil rates i.e. high pressure injection.

It is unlikely that the baseline economic assumption will remain unchanged throughout the project operating life. This particularly true for the crude oil and natural gas prices. In order to evaluate the sensitivity of the project's economic to these important variables, the NPV of the previous simulations are calculated at varying oil and natural gas prices.

Figure 7-14 shows the effect of increasing natural gas price by 100% above the baseline assumption (8.4$/MMBtu). Figure 7-14 shows that the higher fuel cost resulting from higher fuel prices caused the optimum operating pressure to shift from 30 bar (refer to Figure 7-12) to the thermodynamically more efficient 15 bar. It can also be seen that the effect of higher fuel prices is more pronounced for the 45 bar, with over 80% reduction in NPV as shown in Figure7-14. The 15 bar project is predicted to yield more than 300 $MM in profit compared to the 45 project.

Surprisingly, the economics of SAGD under the cogeneration assumption remains in favour of the high pressure injection despite the large increase in fuel price. Figure 7-15 shows that the project NPV remains highest at 45 bar. It can therefore be concluded that incorporating cogeneration helps to decouple the project economics from unpredictable fuel prices.

The effect of higher oil prices on the projects economics at different operating pressure is shown in Figure 7-16. By increasing the oil price from 50 to 100 $/bbl, the 30 bar optimum pressure (shown in Figure 7-12) is shifted to 45 bar. A combination of high oil prices and relatively low natural gas prices (4.2 $/MMBtu) will favour the option with the highest oil rate, which is 45 bar in this case.

The company cumulative discounted cash flows at different operating pressures and under various economic assumptions are shown in Figures 7-17 &7-18.

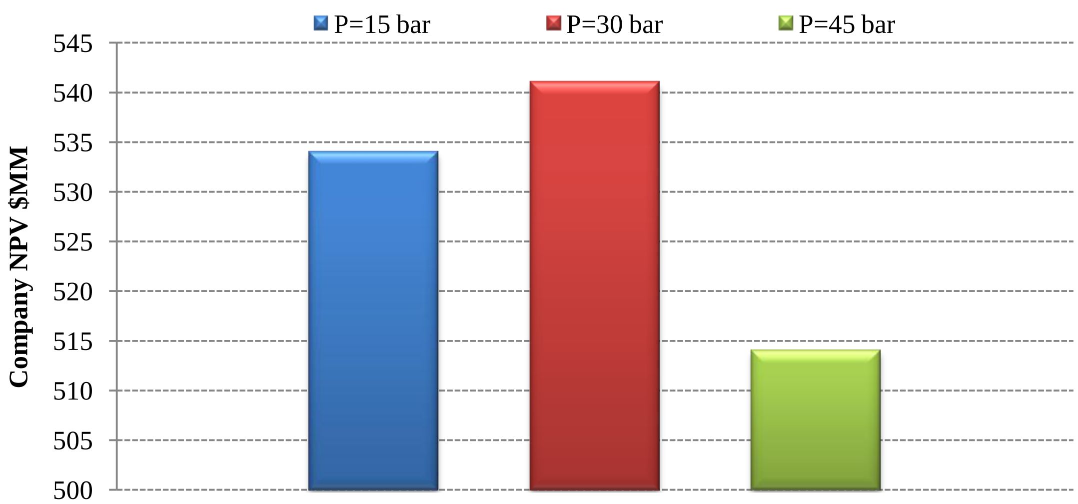


Figure 7-12: Oil company NPV (fired-boilers), Oil Price=$50, Gas Price=$4.2/MMBtu

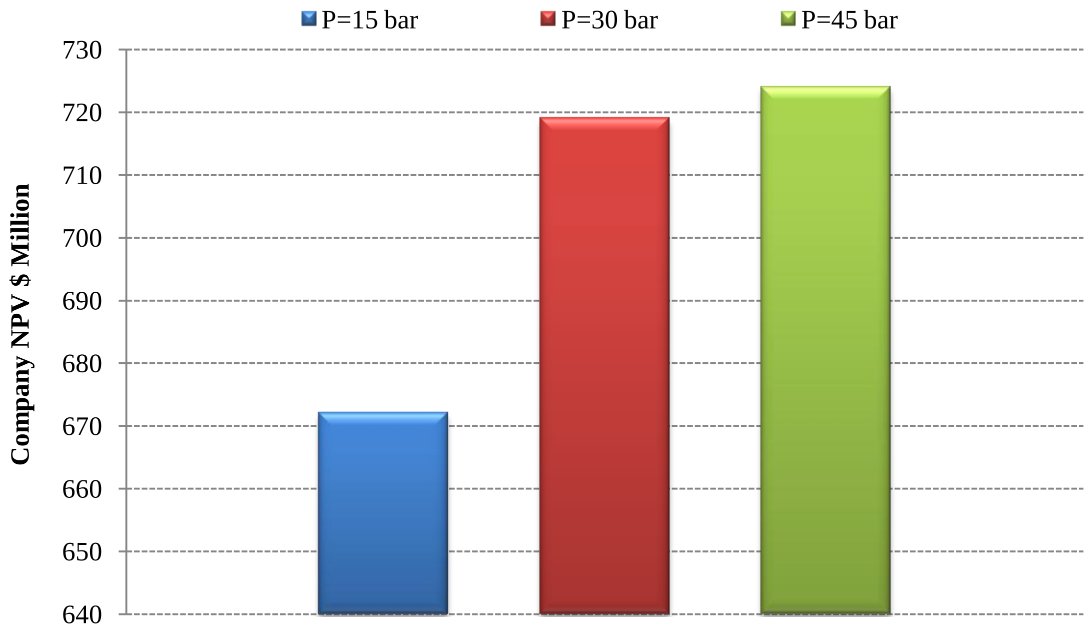


Figure 7-13: Oil company NPV (cogeneration), Oil Price=$50, Price=$4.2/MMBtu

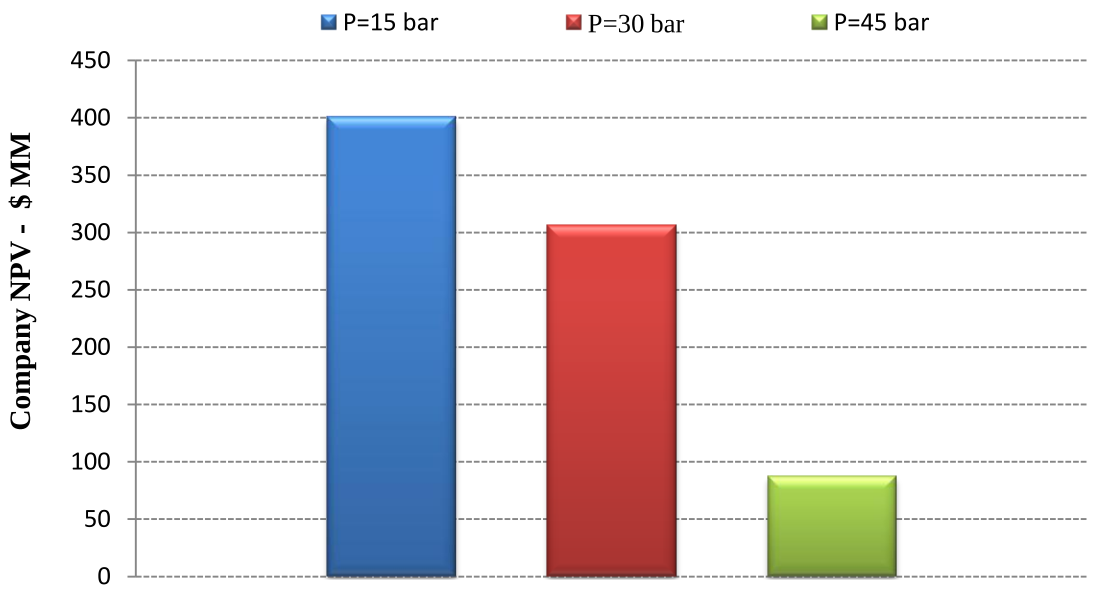


Figure 7-14: Oil company NPV (fired-boilers) Oil Price=$50, Price=$8.4/MMBtu

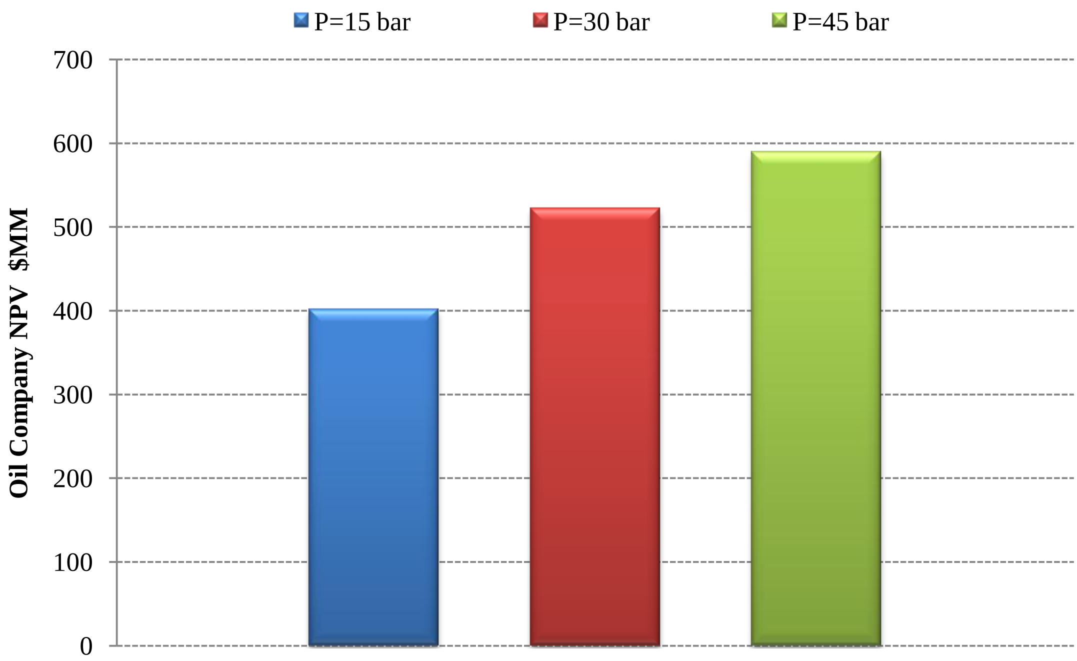


Figure 7-15: Oil company NPV (Cogeneration), Oil Price=$50, Price=$8.4/MMBtu

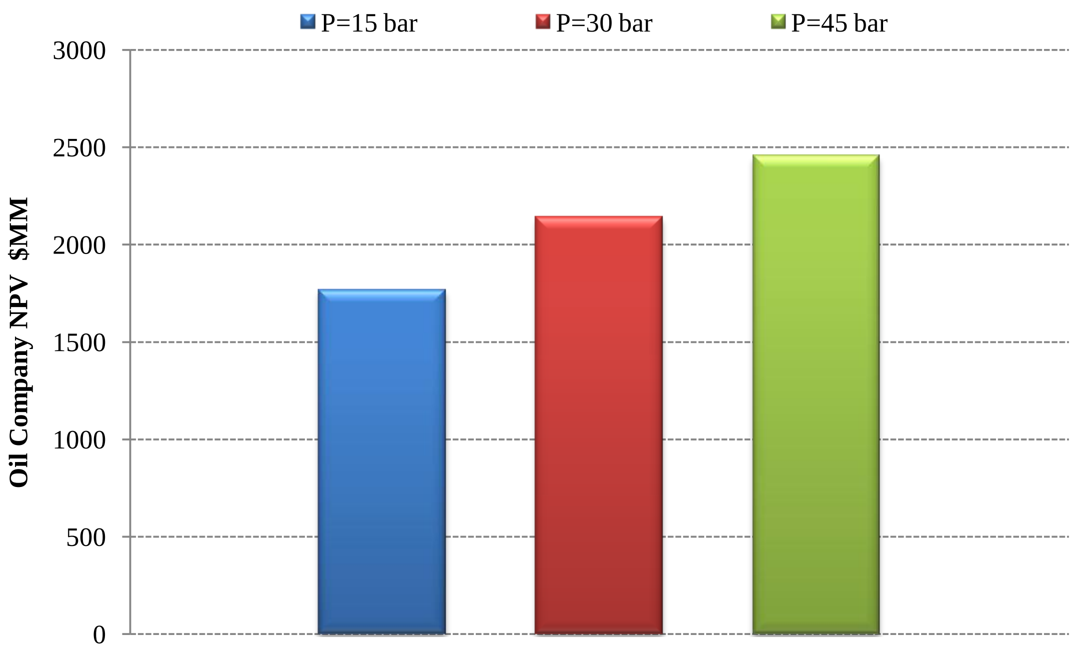


Figure 7-16: Oil company NPV for fired-boilers, Oil Price=$100, Price=$4.2/MMBtu

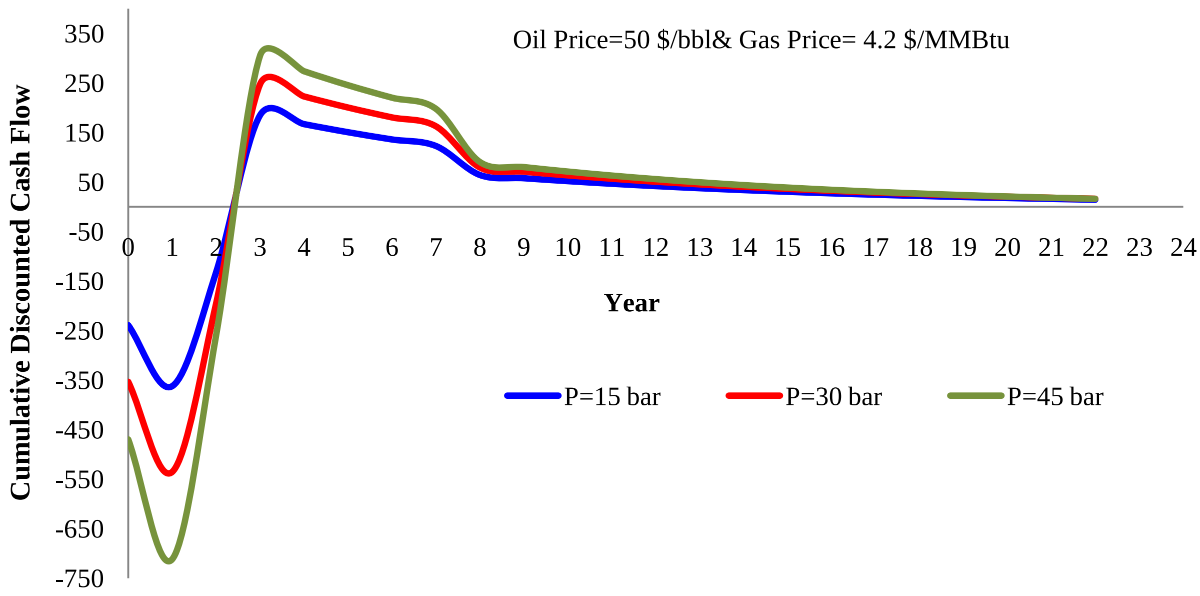


Figure 7-17: Oil company cumulative discounted cash flow at different operating pressures

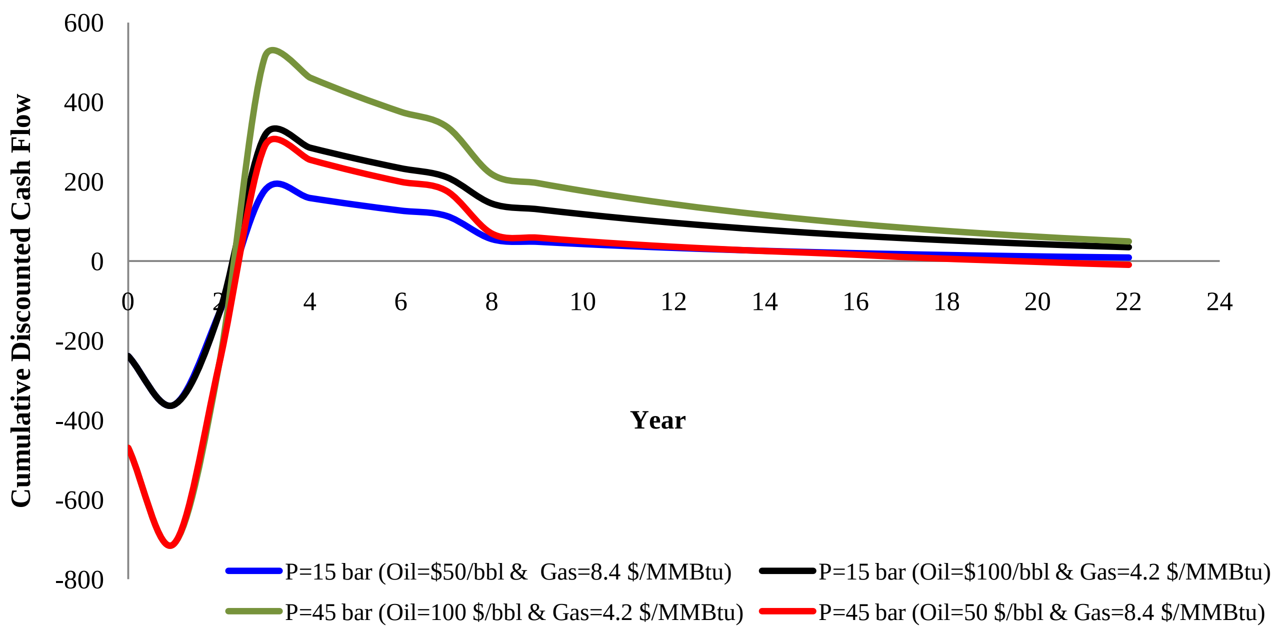


Figure 7-18: Oil company cumulative discounted cash flow at different operating pressures

7.6.5 Government NPV

An interesting observation is made by comparing the oil company and the government NPVs. It was observed that from a government viewpoint, SAGD economics is driven by revenue from oil sales and it is less sensitive to operating costs. Figure 7-19 indicates that the project economics remains in favour of high pressure injection even under the least favourable economic conditions (low oil price versus high fuel price). This is in contrast to the oil company where its share of profit deteriorates remarkably under these operating conditions. There is hence a clear conflict of interest between the two parties regarding the optimum operating pressure.

In order to evaluate if changes to the fiscal arrangement could alter this conclusion, the baseline fiscal arrangement is changed in favour of the oil company. The new fiscal arrangement includes higher cost-recovery percentage, higher split of profit oil, and a reduction in income tax, see Table 7-3.

Results from the new simulations are shown in Figure 7-20. There are two key observations that can be made by comparing Figures 7-19 & 7-20. The first is that the oil company share of profit has increased remarkably under the new fiscal arrangement. Secondly, by only changing some of the fiscal parameters the government optimum operating pressure was shifted from 45 bar to 30 bar, whereas for the oil company the optimum operating pressure remains at 15 bar. Therefore, the proposed changes in fiscal parameters were insufficient to resolve the conflict in optimum operating pressure between the oil company and the government, which demands for one of the party to make a compromise.

Table: 7-3New Economic and fiscal assumptions

Parameter	Unit	Input
Oil Price	$	50
Natural Gas Price	$/MMBtu	8.4
Cost-Oil Percentage	%	90
Profit Oil Split- Government	%	50
Profit Oil Split- Oil Company	%	50
Income tax	%	15

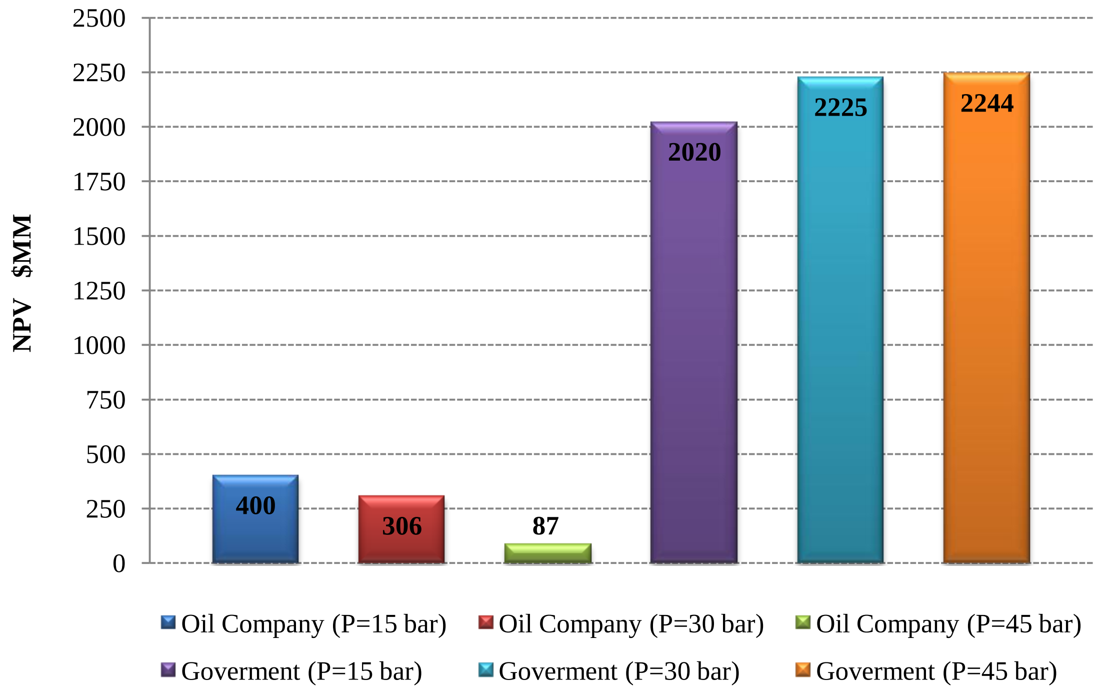


Figure 7-19:NPV (fired-boilers), Oil Price=$50, Price=$8.4/MMBtu

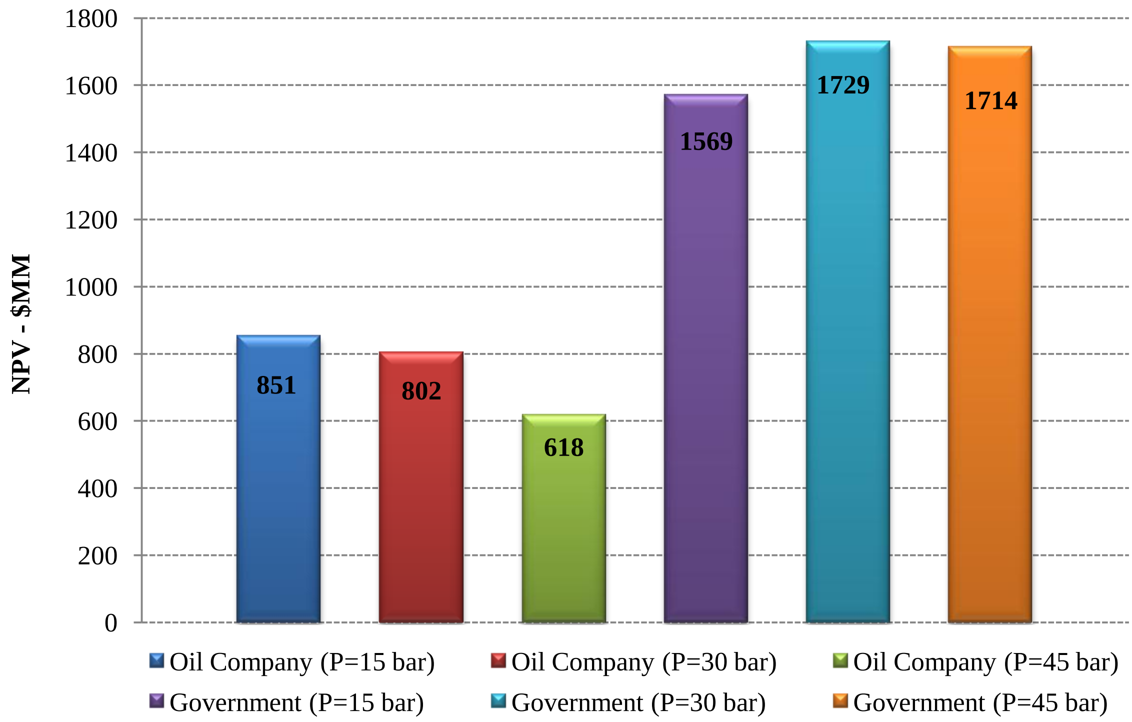


Figure 7-20: NPV under new fiscal arrangement, Oil Price=$50, Price=$8.4/MMBtu

7.6.6 Emissions Tax

As illustrated previously, S-EOR operations emit above than average CO_2. Therefore, environmental regulations that either restrict the amount or impose penalty on the produced CO_2 would have detrimental effects on the project economics and perhaps the project's overall viability.

Figure 7-21shows the impact of a $30 per tonne CO_2 tax on the oil company economics and the optimum operating pressure. Figure 7-21 shows that for the fired-boilers facility the CO_2 tax has caused optimum operating pressure to shift from 30 bar (as shown in Figure 7-12) to the more efficient and less CO_2-intensive 15 bar.

Figure 7-21 also indicates for the cogeneration facility, the maximum NPV is obtained at 30 bar instead of 45 bar previously obtained despite the better efficiency of cogeneration systems. The general trend is that potential CO_2 tax would favour low pressure operations which are expected to consume less fuel and thus emit less CO_2.

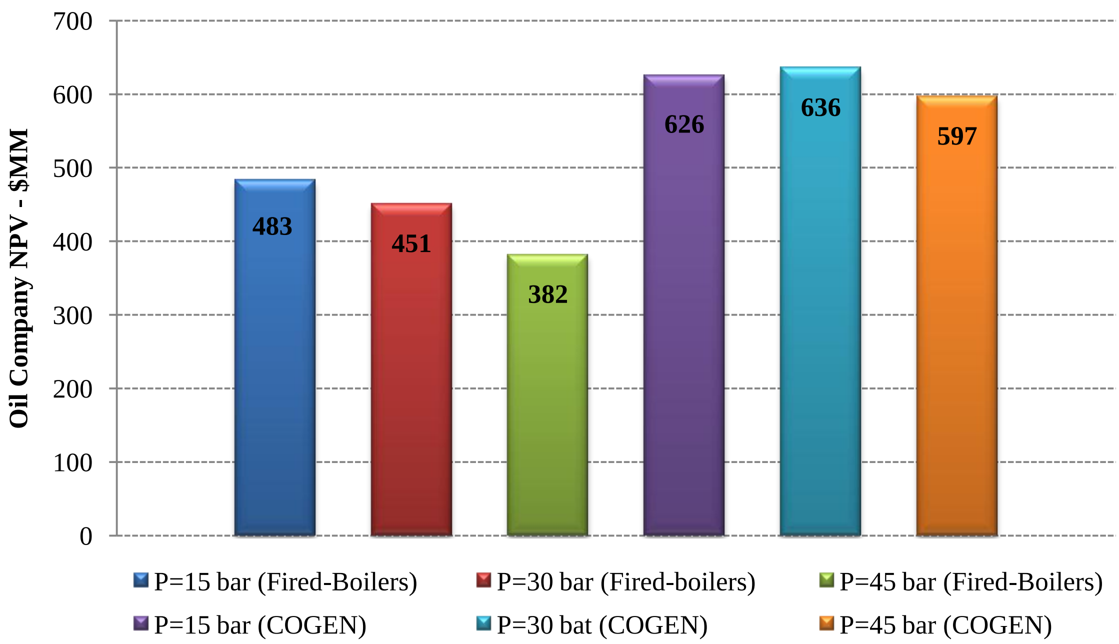


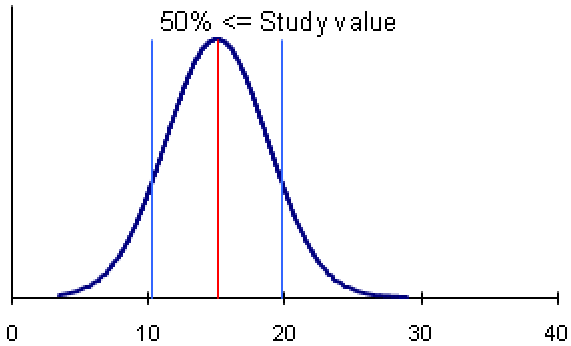
Figure 7-21: Impacts of CO_2 tax on oil company NPV

7.6.7 Monte Carlo Simulations

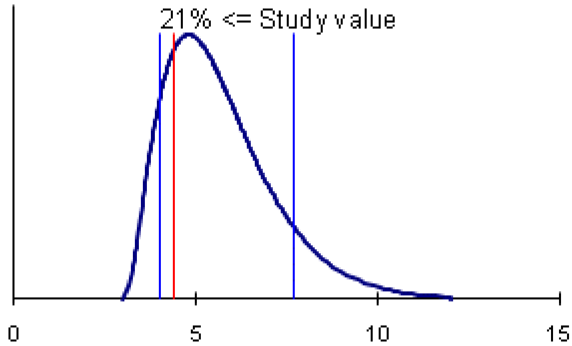
The previous discussions illustrated that there are a number of factors that influence the optimum operating pressure for SAGD. To make matters worse, many of these factors are uncertain and stochastic in nature. This is particularly true for crude oil and natural gas prices. The Monte Carlo model of TERM-EOR is used to generate probability distributions of the project NPV at different combinations of oil prices, gas prices, and CO_2 tax. A full Monte Carlo simulation requires as accurate distribution of each variable as possible. Unfortunately, it is not possible to obtain a continuous cumulative probability function for these parameters. In these circumstances, a more generic type of probability distributions are used which require low, most likely, and high estimations of the selected variables to be specified. The type of distributions selected for the current simulations and the main input parameters are listed in Table 7-4. The Monte Carlo simulations were run for a total of 32,000 times. Outputs from the simulations are shown in Figures 7-23 to 7-28 and a summary is provided Table 7-5.

Figure 7-23 and Figure 7-25 show histogram representations of the oil company's NPV at 15 bar and 45 bar. The plots reveal that in general operating at high pressures is expected to yield higher NPV values. The maximum expected NPV for the 15 and 45 bar is 2232 and 3177 $MM, respectively. However, despite the higher NPV, Monte Carlo Simulations indicate that operating at higher pressures is financially more risky. This is reflected in the minimum expected NPVs. The minimum expected NPV for the 15 bar and 45 bar is (-93) and (-1127) $MM, respectively. Therefore, combinations of unfavourable operating conditions such as high natural gas prices and low crude oil prices coupled with potential CO_2 tax will significantly erode the profitability of high pressure operations. On the other hand, operating at lower pressures, although is expected to yield lower profitability, makes the projects less sensitive to changes in economic conditions.

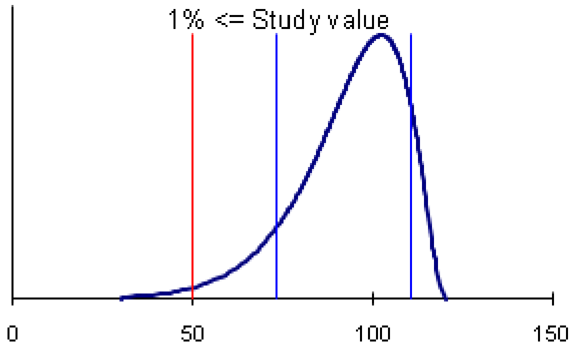
In contrast to the oil company, operating at high pressure seems to be more favourable for the government viewpoint, see Figures 7-27 &7-28. In this case, both the minimum and maximum expected NPV values occur at high pressure injection scenarios, as summarized in Table 7-5.



Normal Distribution-CO_2 Tax



Gamma-Left Distribution- Gas Price



Gamma-Right Distribution- Oil Price

Figure 7-22: Selected distributions for Monte Carlo

Table 7-4: Monte Carlo simulations main inputs

	Input Parameters		
Parameter	**Oil Price ($/bbl)**	**Gas Price ($/MMBtu)**	**CO_2 Tax ($/ton)**
Distribution Type	Gamma-left	Gamma-right	Normal
Study Value	50	4.4	15
Minimum Value Allowed	30	3	0
Maximum Value Allowed	120	12	30

Table 7-5: Monte Carlo simulations main outputs

	Oil Company		Government	
Parameter	**15 (bar)**	**45 (bar)**	**15 (bar)**	**45 (bar)**
Minimum Result $M	-93	-1127	667	809
Maximum Result $M	2232	3177	7291	11002
Expected Value $M	1539	2027	5259	7607
Standard Deviation $M	374	596	1067	1692

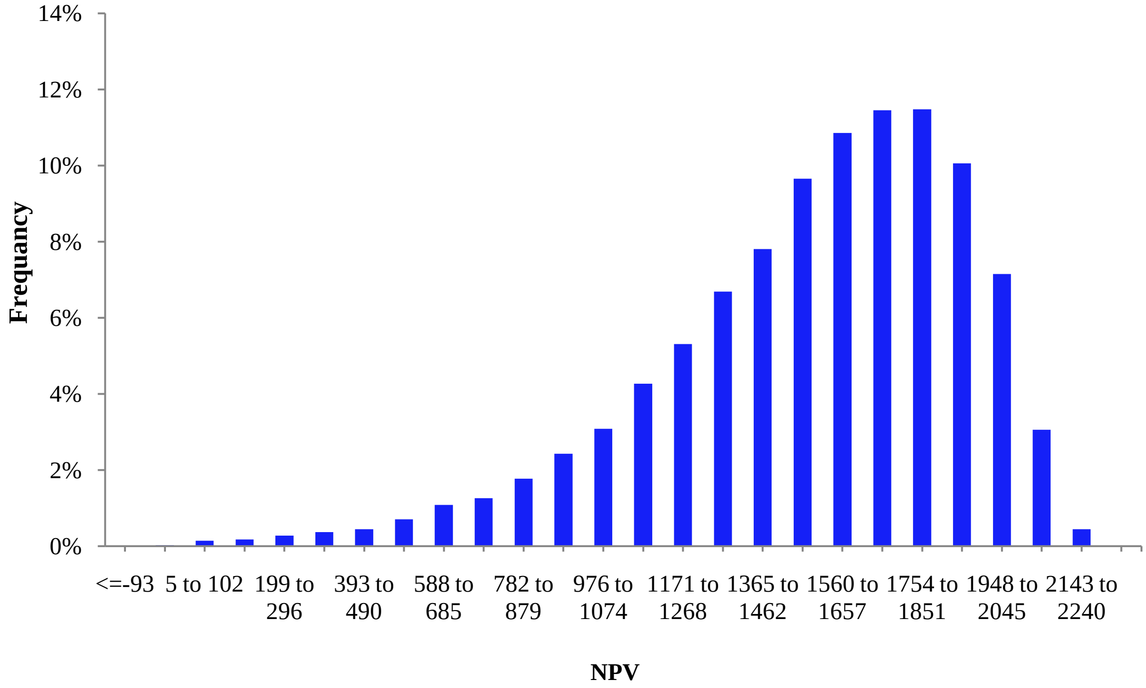


Figure 7-23:Oil company NPV histogram (15 bar operating pressure)

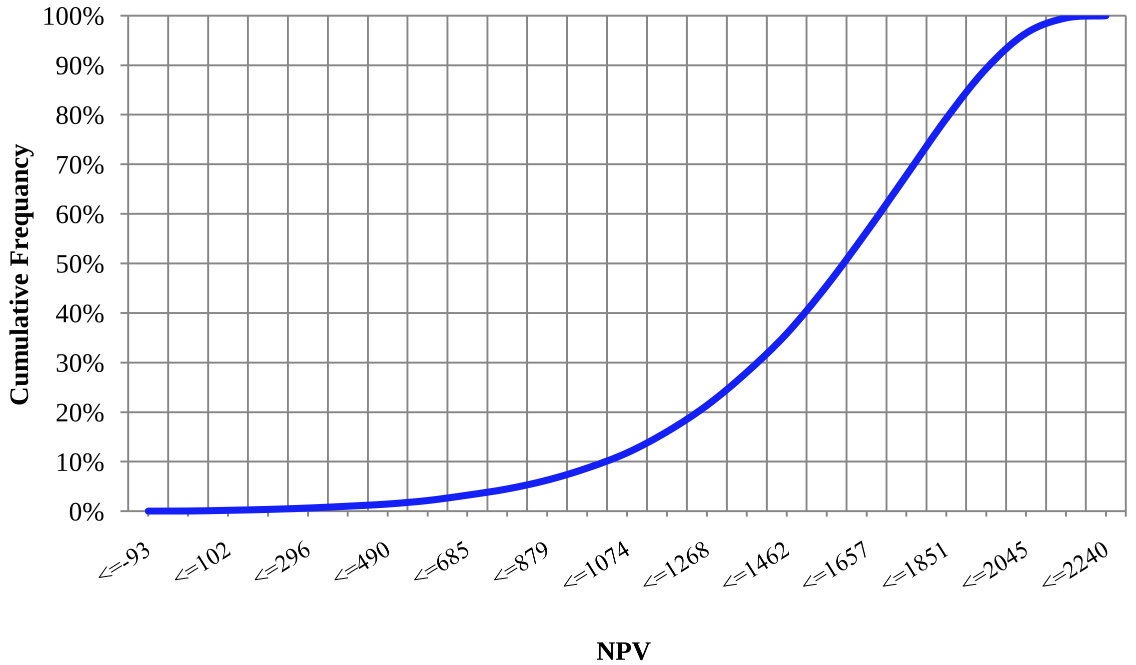


Figure 7-24: Oil company NPV cumulative frequency (15 bar operating pressure)

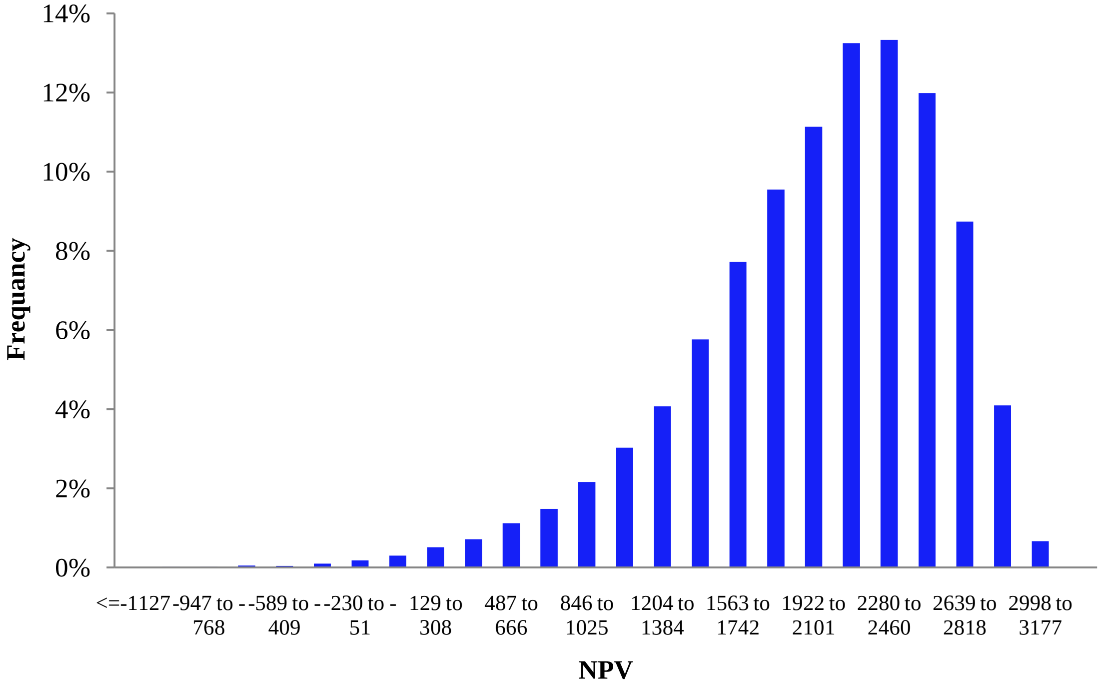


Figure 7-25: Oil company NPV histogram (45 bar operating pressure)

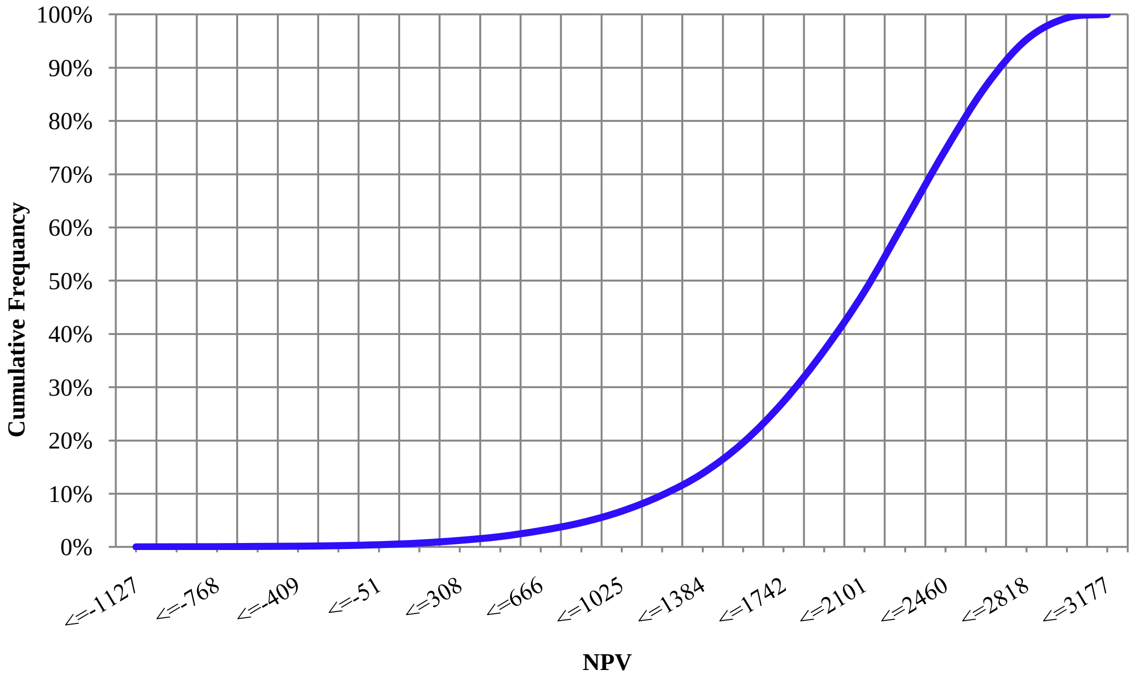


Figure 7-26: Oil company NPV cumulative frequency (45 bar operating pressure)

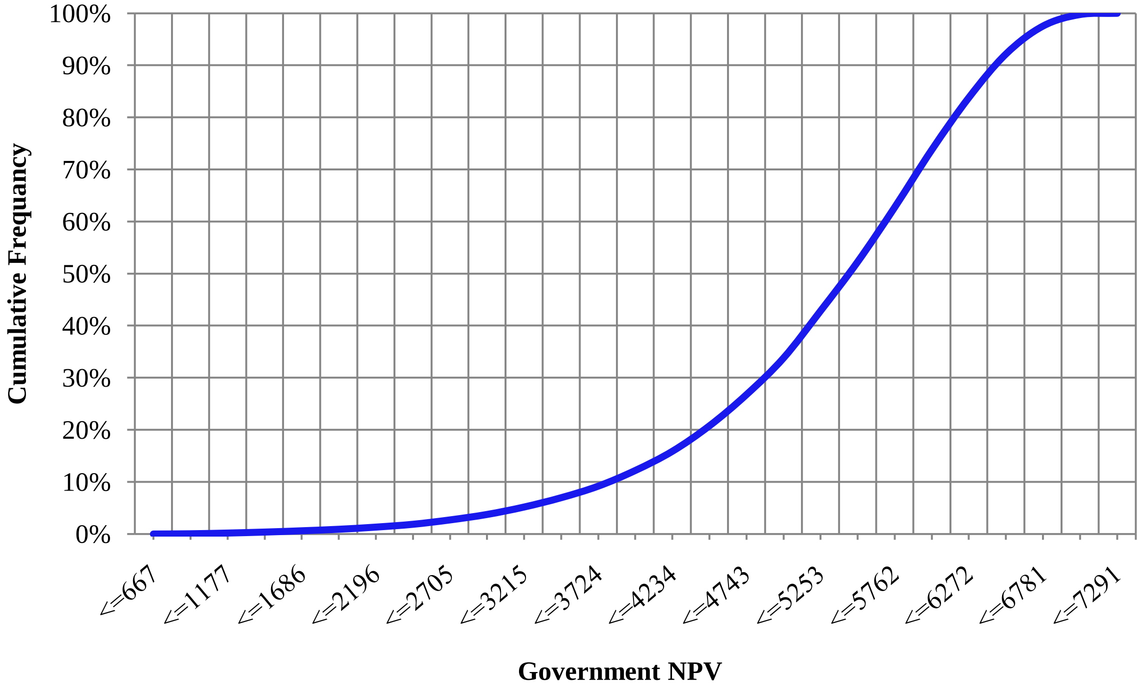


Figure 7-27:Government NPV cumulative frequency (15 bar operating pressure)

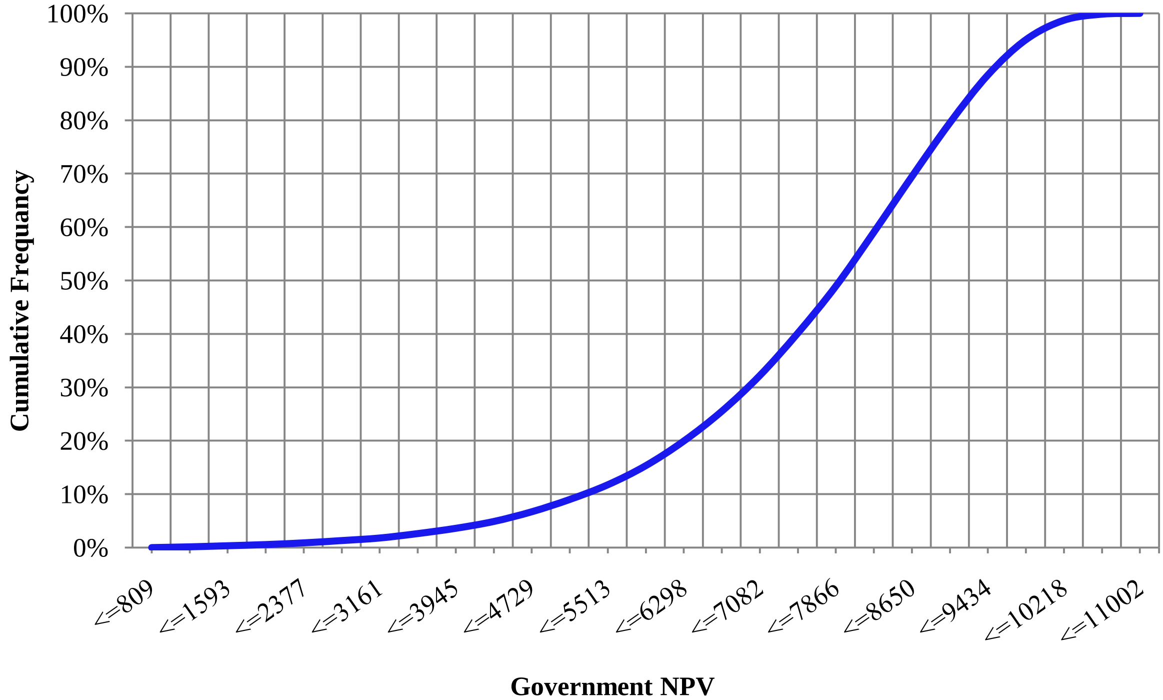


Figure 7-28: Government NPV cumulative frequency (45 bar operating pressure)

7.7 Conclusion

This case study is meant to be general in nature. The general purpose is to illustrate the use of TERM-EOR as a tool for optimizing S-EOR operations, which has been exemplified by comparing LP-SAGD and HP-SAGD operations for an energy viewpoint.

The general conclusion is that there is not cut-off answer to the question of optimum operating pressure for SAGD projects. The answer is found to be influenced by a number of factors including the obtained oil rate, the SOR profile, fuel prices, steam technology, emissions tax, as well as the fiscal arrangement in place.

An interesting finding is the conflict in optimum operating pressure between the oil company and the government. From an oil company prospective, Monte Carlo simulation suggests that LP-SAGD although is likely to generate less revenues, is financially more robust. It can therefore be concluded that for an oil company prospective, the economics of SAGD projects is more sensitive to the SOR than the oil production rate. On the other hand, the government's NPV seems to be driven by the obtained oil rate and for that reason it favours high pressure injection.

The use of energy efficient technologies such as cogeneration alters the decision making process by making the economics of the project less sensitive to the SOR profile; shifting the balance in favour of high pressure injection.

To conclude, the economics of SAGD projects is highly dependent on the operating pressure. There is therefore a large potential saving in the order of millions that could be realized by optimizing the injection pressure for the considered field. This optimum can only be found by the mean of multidisciplinary evaluation, as demonstrated in this chapter.

Finally, this case study has demonstrated the usefulness of TERM-EOR as a tool for evaluating S-EOR projects and the necessity of such approach toward optimum decision making.

8 Conclusions: Comments and Recommendation

8.1 Comments

1. A techno-economic and risk evaluations tool for the evaluation of thermal EOR projects has been developed and later demonstrated through two case studies.

2. Under the rang of SOR considered in this study, natural gas required to recover a barrel of oil was found to vary from 900 to 3,200 cf/bbl and the associated CO_2 emissions to vary from 75 to 170 kg.CO_2/bbl. The use of produced crude oil for steam generations found found to be uneconomical under most scenarios and results in higher fuel prices and CO_2 emissions.

3. Integrating the solar technology into S-EOR operations, although is believed to be feasible from subsurface view point, would impose a number to technical challenges. It has been found that larger number of injection wells may be needed to accommodate peak rate associated with solar system. It has also been predicted that steam for field injection would only be available for less than nine hours a day, after which steam injectors have to be shut-in. In this case, the mechanical integrity of the steam injection wells could be jeopardized due to thermal cycles.

4. There is a large potential saving that could result from optimizing operating conditions of S-EOR using multi-disciplinary tools such as TERM-EOR. In the first case study, TERM-EOR predicted more than $ 300 million difference in NPV for a 30 bar difference in operating pressure for a SAGD project.

5. In the second case study, the thermodynamic and economic performance of cogeneration in a S-EOR project was evaluated. Given the assumptions considered in the case study, cogeneration was economically feasible even under the most unfavourable conditions. The break-even oil price for the project with cogeneration was also found to be six to eight dollars lower than that without.

8.2 Recommendations

1. A subsurface oil recovery model for the CSS process has not been included in TERM-EOR. Adding such capability will improve the versatility of TERM-EOR.

2. In this study the heat losses in surface steam pipes and wellbore are neglected. These losses, although are typically not significant, but can add to the project costs. Therefore, a sub-model that predicts these losses would enhance TERM-EOR capability.

3. A significant improvement to the current work can be obtained by adding optimizations capabilities to TERM-EOR.

4. Detailed economic analysis of the solar case is also needed. The solar should be evaluated against cogeneration since this technology is becoming the baseline option in S-EOR projects.

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